Review of Ergon Energy's revised regulatory proposal for the period July 2010 to June 2015

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for the Australian Energy Regulator

Parsons Brinckerhoff Australia Pty Limited
ABN 80 078 004 798

Level 7
457 St Kilda Road
MELBOURNE VIC 3004
PO Box 7209
MELBOURNE VIC 8004
Australia
Telephone *+61 3 9861 1111*
Facsimile *+61 3 9861 1144*
Email *melbourne@pb.com.au*

Certified to ISO 9001, ISO 14001, AS/NZS 4801

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Author: V.Petrovski, J.Thompson, A Smith, J Tok, P.Walshe,

Signed: ....

Reviewer: Peter Walshe

Signed: ....

Approved by: Peter Williams

Signed: ....

Date: ....

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

Totals in tables may not add due to rounding errors.

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 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.

PB provided advice to AER about the Ergon Energy regulatory proposal in November 2009 and the AER released its draft decision also in November 2009. In January 2010 Ergon Energy submitted a revised regulatory proposal.

The AER now requires PB to review and provide advice on a number of issues raised in this revised expenditure proposal, to inform its final decision and distribution determination.

The areas selected for inclusion in PB's terms of reference were based on a considered view by the AER, in consultation with PB, on the extent of new information included by Ergon Energy in its revised proposal, the materiality of the expenditure adjustments, and the relevance and experience PB of PB's previous engagement.

1.2 Terms of reference

PB is required to produce a report providing technical advice and comment on aspects of Ergon Energy's revised regulatory proposal. In preparing its report, PB is to:

- consider any new information provided by the DNSP as part of its revised proposal and advise of any revisions to the recommendations made by it in its previous reports
- provide details of any revisions to the DNSP's revised opex and capex allowances as a result of any changes it recommends
- set out what new information and reasoning has led to the revision of any of its previous recommendations. If no such changes are made in relation to issues raised by the DNSP, PB must set out why the DNSP's responses and new information do not lead to a revised recommendation.

Within its report, PB 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.

Table 1.1 outlines the elements under review by PB. These were selected in conjunction with the AER. The type of review is classified as either Detailed or High Level to provide an indication to PB of the weighting, importance and effort to be placed on each of the elements considered.

Table 1.1 Elements under review by PB

Expenditure category	Type of review
Forecast capex element	
Corporate initiated growth capex – demand forecast sensitivity	Detailed
Customer initiated capex – forecast methodology	Detailed
Asset replacement - methodology	Detailed
Reliability and quality capex - escalators	High level
CPI and capex cost escalation process	High level
Forecast non-system capex element	
ICT capex initiatives – justification	Detailed
ICT capex initiatives – change program	Detailed
Property - justification	Detailed
Forecast opex element	
Pole inspections	Detailed
Service inspections overlap	High level
Veg management – cumulative growth	High level
Keys and locks	High level
Removal of old poles	High level
Access track work volume	Detailed
Forced maintenance volume	Detailed
Alternative control – metering and customer services	Detailed
Demand management PM	High level
GSL payments – forecasting methodology	High level
STPIS element	
Reliability of supply – performance targets (MSS-10%)	High level
Telephone answering parameter – MED's	High level

Source: AER

PB has primarily undertaken a desktop review of Ergon Energy's revised proposal as the timeframe for the review provided only limited opportunity for PB to clarify any new information. PB has, however, sought specific clarification through written requests and responses in areas that it considered important to its findings.

1.3 Report structure

This report is supplementary to and should be read in conjunction with PB's 2009 report, 'Review of Ergon Energy regulatory proposal for the period July 2010 to June 2015'. A copy of this report is available from the AER's website.

In Sections 2 and 3 we review Ergon Energy's revised forecasts for system capex and non-system capex respectively. In section 4 we review the revised opex forecasts, while section 5 considers the revised Service Target Performance Incentive Scheme.

2. Forecast Capex

In this section PB reviews the following matters in relation to Ergon Energy's revised forecast capex proposal:

- Corporate initiated growth capex – demand forecast sensitivity
- Customer initiated capex – forecast methodology
- Asset replacement - methodology
- Reliability and quality capex – escalators.

2.1 Corporate initiated augmentation growth capex – demand forecast sensitivity

PB is required to provide updated advice on the methodology for, and amount of, any adjustment necessary to Ergon Energy's revised corporation initiated augmentation capex (CIA, or 'growth capex') proposal as a result of an adjustment to forecast demand, subject to McLennan Magasanik Associates (MMA) recommendations on the reasonableness of Ergon Energy's revised demand forecasts.

In its original proposal, Ergon Energy proposed a total of $1,991.0m of CIA capex for the next regulatory control period. Following a detailed review, the AER did not accept Ergon Energy's demand forecasts, and in its draft decision made an adjustment of $526.3m to the CIA capex allowance to reflect a realistic expectation of demand.

In making its draft decision, the AER had regard to PB's advice that it was unable to conclude that Ergon Energy's proposed CIA capex was efficient due to limited and incomplete business documentation to demonstrate efficiency (i.e. business cases or similar documents), and that PB was unable to establish a clear relationship between the planning documentation and the SC capex data model. Furthermore, the AER also had regard to the advice of MMA regarding Ergon Energy's demand forecast, and PB's advice regarding the impact on the proposed CIA capex of deferring demand growth for 1 to 2 years.

2.1.1 Revised proposal and new information

In its revised proposal, Ergon Energy has rejected the AER's draft determination, and has submitted a CIA proposal of $2,076.3m, which represents its original proposal adjusted to account for changes in cost escalators and the reallocation of overheads. This revised proposal is based on the original information, as well as additional supporting material and new information which has become available since submission of its original proposal.

In its revised proposal, Ergon Energy sets out a number of supporting arguments and has provided a report prepared by the Huegin Consulting Group (Huegin). In summary, Ergon Energy argues that in its view the AER's alternative forecast cannot be utilised as it[1]:

[1] Ergon Energy Corporation Limited, 2010, *"Confidential Revised Regulatory Proposal to the Australian Energy Regulator, Distribution Services for 1 July 2010 to 30 June 2015"*, p. 104, 14 January 2010.

- incorrectly assumes that the supporting planning documentation does not align with the capital expenditure forecast

- relies upon MMA's top-down global demand forecast, which is flawed in approach, utilises incorrect data, and is less accurate than the approach employed by Ergon Energy[2]

- relies on 'sensitivity analysis' which significantly overstates the proportion of capex that is sensitive to the deferral of demand

- is inconsistent with previous regulatory determinations.

Ergon Energy's revised proposal presents a number of specific arguments in relation to these points, and based on the consideration of these arguments, Ergon Energy has resubmitted its original CIA capex proposal with some adjustments for cost escalator changes and overhead reallocation.

2.1.2 PB findings and recommendation

PB has reviewed Ergon Energy's revised proposal and the supporting material provided. Our review of the issues raised by Ergon Energy in relation to its CIA capex proposal is addressed in the following sections.

It should be noted that consideration of the accuracy of Ergon Energy's demand forecast, and the material relating to it, is not within PB's scope of work. Accordingly, our review does not address this material. However, PB has had regard to the advice provided to the AER by MMA in relation to the application of Ergon Energy's revised demand forecast[3].

Demand sensitivity

In our original review of Ergon Energy's CIA capex, PB considered the implications of MMA's findings with respect to the reasonableness of the demand forecasts which underpin Ergon Energy's proposed CIA capex. Based on advice from Ergon Energy regarding the portion of the CIA capex driven by the demand forecasts[4], and MMA's findings regarding Ergon Energy's forecasts[5], PB undertook a high-level assessment of the impact of demand forecast changes on Ergon Energy's CIA capex proposal[6]. The AER subsequently accepted PB's advice with regards to this issue.

In its revised proposal, Ergon Energy argues that the AER's alternative forecast cannot be utilised as it relies on a sensitivity analysis which overstates the demand sensitive proportion of the CIA capex[7]. To support this argument, Ergon Energy refers to an assessment undertaken by Huegin of the demand sensitive portion of the CIA capex. Huegin's findings are summarised in Table 2.1.

2 While this matter is not within PB's scope of work it has been included here for completeness only.

3 McLennan Magasanik Associates , 2010, *"Draft report to Australian Energy Regulator - Maximum demand forecasts for the Ergon Energy region – update addendum"*, 1 March 2010.

4 Ergon Energy email reply to questions AS.46, AS.109 and AS.112 29/08/09

5 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.

6 Parsons Brinckerhoff Australia Pty Limited, 2009, *"Review of Ergon Energy regulatory proposal for the period July 2010 to June 2015"*, pp.36-37, 24 November 2009.

7 Ergon Energy Corporation Limited, 2010, *"Confidential Revised Regulatory Proposal to the Australian Energy Regulator, Distribution Services for 1 July 2010 to 30 June 2015"*, p. 104, 14 January 2010

Table 2.1 Detailed breakdown of CIA cost categories against forecast demand sensitivity

Original classification	Additional detail	Percentage of total CIA	Forecast demand driven?
Existing security (N-1) breaches	N/A	7.7	No
Forecast security (N-1) breaches	N/A	55.4	Yes
Specific issues	Voltage outside of statutory limits	11.5	Both existing and forecast issues
	Power quality outside of standards	1.3	No
	Equipment below required rating (thermal and fault level)	19.4	Both existing and forecast issues
	Operational/Safety/Reliability enhancement	4.7	No
	Load control augmentation	<0.1	No

Source: *Huegin Consulting Group, 2010, "Review of Qld Draft Determination & Parsons Brinckerhoff Report on Ergon Energy's Regulatory Proposal", p.16, 12 January 2010.*

We note that Ergon Energy's subject matter experts and Huegin have not been able to verify from a bottom-up perspective the proportion of the "specific issues" category that is not demand driven, and instead Huegin has offered a range estimate, stating that:

> *"The data made available to Huegin suggests that between 13.7% and 44.7% of the total CIA expenditure amount should be excluded from any such adjustment process, as opposed to the 7.7% used by PB."*[8]

While we believe it is reasonable to expect that Ergon Energy should be able to verify the portion of capex that is sensitive to the demand forecast from a bottom-up perspective, PB nonetheless accepts that a portion of the "specific issues" category contains work that is not sensitive to demand forecast. Based on the results presented in Table 2.1, we also accept that the proportion of CIA capex that is sensitive to the demand forecast is somewhere between 55.4% and 86.3%. However, as we are unable to conclude specifically what this proportion should be, for the purposes of further analysis PB has recognised the detailed breakdown presented by Huegin and progressed based on the assumption that the average value of 70.9% is the proportion of total CIA capex that is sensitive to variation in the demand forecast.

In relation to the basis of the AER's alternative forecast, Ergon Energy also makes the following points[9]:

- a proportional change in CIA capex with demand does not account for variation across feeders, and incorrectly assumes that system maximum demand changes can be homogenously applied proportionally across the network

8 Huegin Consulting Group, 2010, *"Review of Qld Draft Determination & Parsons Brinckerhoff Report on Ergon Energy's Regulatory Proposal"*, p. 17, 12 January 2010.

9 Ergon Energy Corporation Limited, 2010, *"Confidential Revised Regulatory Proposal to the Australian Energy Regulator, Distribution Services for 1 July 2010 to 30 June 2015"*, p. 105, 14 January 2010. See also Huegin Consulting Group, 2010, *"Review of Qld Draft Determination & Parsons Brinckerhoff Report on Ergon Energy's Regulatory Proposal"*, pp. 17-19, 12 January 2010.

- the AER has advised that global (top-down) methodologies were only appropriate as a high level assessment of reasonableness, and that spatial forecasts are required to assess necessary network expenditure

- it is not valid to model the reduction in CIA capex resulting from a reduction of forecast demand using a proportional decrease based on the difference between the average annual growth rates of two maximum demand scenarios, and any adjustment made in this manner is likely to result in a higher reduction in expenditure than would be established if the demand forecast were applied bottom-up.

In PB's original review, we were unable to reasonably establish the relationship between Ergon Energy's demand forecasts and the proposed CIA capex[10]. Consequently, PB applied a 'high-level' assessment based on MMA's view that the demand forecast overstated the expected growth by one or two years. In our review, PB recognised that the methodology applied was a high-level approach intended to test the reasonableness of Ergon Energy's proposed CIA capex. In PB's view, the method applied is clearly not intended to model the variation in demand growth at a feeder level, and as it essentially averages the impact of demand growth on capex over time across the whole network, it is more indicative of long run investment trends.

PB accepts that the most accurate and robust method to determine the required level of CIA capex is through the detailed bottom-up application of a rigorous network planning process. In our opinion, such a process would essentially replicate the annual engineering planning functions within the business and clearly demonstrate the prudence and efficiency of proposed capex through a direct and observable relationship between the identified need, the selected option, and the capex proposal. However, in our review of Ergon Energy's original proposal and its supporting information, and following detailed discussions with Ergon Energy, we were unable to reasonably establish this relationship. We also note that previously the QCA's consultant experienced similar issues with concerns regarding the supporting information relating to project need, options, and timing[11], but nonetheless was able to conclude that the projects reviewed *"… were generally prudent, with few exceptions"* [12], and "… generally appeared to be efficient" [13].

In relation to the top-down method applied by PB, Ergon Energy also argues that *"… any adjustment made in this manner is likely to result in a higher reduction in expenditure …"*[14]. PB disagrees with this point. While we agree that the method is a high-level view of the impact of deferring demand growth, and as such has an associated uncertainty, in our opinion there is no reason inherent in the method itself that would cause a systematic overstatement or understatement of the results. The method used by PB in assessing the impact of MMA's view of demand growth deferral essentially amounts to deferring the CIA capex in proportion to the demand forecast deferral, and while the structure of the capital portfolio itself may have an impact, we are of the opinion that the method itself is not inherently biased.

10 PB, *"Review of Ergon Energy regulatory proposal for the period July 2010 to June 2015"*, pp.36, 24 November 2009.

11 Burns and Roe Worley Pty Ltd, 2004, "Capital & Operating Expenditure Study for Distribution Network Service Providers in Queensland – Ergon Energy, Final Report", p.88, 21 December 2004.

12 ibid, p.89.

13 ibid, p.90.

14 Ergon Energy Corporation Limited, *"Confidential Revised Regulatory Proposal to the Australian Energy Regulator, Distribution Services for 1 July 2010 to 30 June 2015"*, p.105, 14 January 2010. See also Huegin Consulting Group, *"Review of Qld Draft Determination & Parsons Brinckerhoff Report on Ergon Energy's Regulatory Proposal"*, pp. 18-19, 12 January 2010.

In MMA's review of Ergon Energy's revised proposal, MMA presents its considerations and concludes that[15]:

> *"Based on MMA's assessment, the Ergon Energy forecasts used in its revised proposal are substantially below the Ergon 2007 forecasts used to prepare capex forecasts. …*
>
> *MMA does not consider the new material and forecasts provided by Ergon Energy have substantiated the use of Ergon Energy's 2007 capex forecasts.…*
>
> *… both the Ergon Energy 2009 forecasts and the NIEIR 2009 forecasts are substantially below the analogous forecasts in 2007 – primarily due to the effects of the GFC which were not considered in the 2007 forecasts.…*
>
> *In terms of forecast regional sum of maximum demand the Ergon Energy 2009 and NIEIR 2009 forecasts are some 5.6% pa and 3% pa below the Ergon Energy 2007 forecasts across the 2011 regulatory period.…*
>
> *After updating, MMA's indicative forecasts of Ergon Energy system maximum demand are some 5% pa below the Ergon Energy 2007 forecasts."*

MMA's revised demand forecast is approximately 5%, or 157 MW, on average below Ergon Energy's 2007 demand forecast. PB notes that Ergon Energy's 2007 demand forecast exhibits an average annual growth of 94 MW. This difference implies an approximate 20 month deferral between Ergon Energy's and MMA's forecasts. We note that this difference is essentially similar to the 18 month deferral applied by PB in our previous review.

Following our review of Ergon Energy's original proposal, PB was unable to reasonably conclude that the proposed CIA capex was prudent or efficient, as in our view Ergon Energy had not provided information to reasonably demonstrate its prudency or efficiency. We note that in its revised proposal, Ergon Energy has not produced any new or additional information to demonstrate the prudency or efficiency of the proposed CIA capex – as discussed further in the following section. Rather Ergon Energy's arguments focus on the use of sensitivity analysis as the basis of a recommended adjustment to the proposed CIA capex. PB agrees that the sensitivity analysis is a high-level assessment, and that the most accurate and robust method to determine the required level of capital expenditure is through the detailed bottom-up application of a rigorous network planning process. However, we also note that in our opinion Ergon Energy has not been able to demonstrate this, and the information provided by Ergon Energy does not enable examination of the deferral of the demand forecast at this level. We also note that while Ergon Energy has been unable to determine the proportion of the CIA capex that is sensitive to the demand forecast, that this proportion is likely to be around 71%. PB accepts this approximation and has applied it in our revised calculations.

Supporting documentation

In its revised proposal, Ergon Energy argues that the AER's alternative forecast of CIA capex cannot be utilised as it incorrectly assumes that the supporting planning documentation does not align with the capital expenditure forecast. In its revised proposal

15 McLennan Magasanik Associates, 2010, *"Draft report to Australian Energy Regulator - Maximum demand forecasts for the Ergon Energy region – update addendum", pp. v-vi,* 1 March 2010.

Ergon Energy presents arguments in support of this point, specifically that business case documentation does not ensure efficiency, and that reconciliation of the planning documentation and proposed CIA capex can be demonstrated.

Ergon Energy argues that *"the consideration of options alone does not ensure efficiency, and any finding of relative efficiency … should only be considered if there is direct evidence that the capital expenditure is not efficient"*[16]. PB does not agree with this principle. In our view, prudent expenditure requires appropriate demonstration that the proposed expenditure is reasonably likely to be the most efficient option to address the identified need, given the set of all reasonable or practical options available within the context of the business and its future capital portfolio. Moreover, this principle is embodied in Chapter 6 of the NER, which requires capital expenditure to reasonably reflect the efficient costs of achieving the expenditure objectives.

Further to this, Ergon Energy argues that while not always documented, subject matter experts select the most appropriate option for each project. In our review of Ergon Energy's original proposal, we examined the documentation that was made available, and requested meetings with the relevant subject matter experts in order to establish demonstration of the efficiency of the proposed CIA capex. In our opinion, Ergon Energy did not provide PB with reasonable access to its relevant subject matter experts. We also note that in relation to the question of documentation demonstrating the efficiency of the proposed investment, Huegin concluded similarly to PB, stating that:

> *"… in a number of cases this decision process has been documented, and includes detailed NPV analysis to show that the preferred option is the most efficient, while in many other cases this decision process may not be documented to a standard that enables an external evaluation of individual project efficiency."*[17]

With consideration of the options for many projects not always documented or not documented to a standard that enables an external evaluation, PB cannot conclude that the proposed CIA capex is efficient through examination of the proposal documentation. Moreover, with little access to the relevant subject matter experts, PB also cannot conclude that the proposed CIA capex is efficient through interviews with these experts.

Ergon Energy further argues in its revised proposal that it is not feasible or practical to have business case documentation available for all proposed projects. PB agrees that for a DNSP to have business case documentation available for all projects over a period up to 7 years in advance is difficult, although it is not uncommon in our experience for high value projects, particularly those proposed for early in the regulatory period, to be supported by business case documentation (or similar material). As pointed out by Ergon Energy, PB has in other reviews considered alternative business information made available by the business to demonstrate the prudence and efficiency of its capex proposals where business case documentation was not reasonably available. However, in Ergon Energy's case, we note that no other alternative information has been provided to demonstrate efficiency of the proposed corporation initiated augmentation capex.

16 Ergon Energy Corporation Limited, 2010, *"Confidential Revised Regulatory Proposal to the Australian Energy Regulator, Distribution Services for 1 July 2010 to 30 June 2015"*, p. 104, 14 January 2010. See also Huegin Consulting Group, 2010, *"Review of Qld Draft Determination & Parsons Brinckerhoff Report on Ergon Energy's Regulatory Proposal"*, p. 13, 12 January 2010.

17 Huegin Consulting Group, 2010, *"Review of Qld Draft Determination & Parsons Brinckerhoff Report on Ergon Energy's Regulatory Proposal"*, p. 13, 12 January 2010.

Sub-transmission augmentation reconciliation

In relation to the reconciliation between planning documentation and CIA capex forecast, Ergon Energy engaged Huegin to investigate the reconciliation issue noted by PB in our original report[18]. Huegin found that it was able to reconcile the source and exact quantities between the capital expenditure model and the planning documentation for 100% of the Sub-Transmission Network Augmentation Plan (SNAP) and 99.7% of the Distribution Network Augmentation Plan (DNAP)[19].

Notwithstanding this additional analysis, PB was still unable to reconcile the units contained in the Huegin reconciliation with the sub-transmission planning documentation and requested through written questions further clarification regarding the commissioning dates, scope of work and options considered for the projects identified by Huegin as comprising approximately 66% of Ergon Energy's sub-transmission CIA capex forecast.

In response to PB's enquiries, Ergon Energy advised that the Huegin reconciliation and the original proposal were based on the 2007 SNAP and not the 2008 SNAP. This was because the 2007 SNAP was developed in accordance with the more conservative network security criteria recommended by the Queensland government[20] following the EDSD review. In contrast, the 2008 SNAP was developed on the assumption that the joint Ergon Energy and Energex proposal to allow the more efficient use of mobile substations and mobile generation to meet the security guidelines would be accepted by the Department of Mines and Energy (DME). Ergon Energy also advised that the regulatory proposal was prepared on the basis of the 2007 SNAP as the "*… most up to date and relevant SNAPS available at the time of the forecast*"[21] notwithstanding that the 2008 SNAPs were available at the time of submission and Ergon Energy had received preliminary advice from the DME that the security criteria may be relaxed from N-1 to N in some situations[22,23].

Reconciliation with 2007 SNAPs

On the basis of Ergon Energy's advice regarding its dependence on and use of the 2007 SNAP, PB attempted to reconcile the projects identified in the Huegin report as comprising the Ergon Energy CIA capex proposal with the 2007 SNAP documents. Significantly, PB found a number of abnormalities in the reconciliation:

- in three cases[24] projects are included in the Huegin reconciliation with commissioning dates well outside the regulatory control period. For example, in the case of the Blackwater 22kV Regulator Augmentation the full cost of the project is included despite a November 2017 commissioning date which falls outside the two year project timeframe identified by Ergon Energy for projects with partial expenditure in the regulatory control period [25]

18 PB, Review of Ergon Energy regulatory proposal for the period July 2010 to June 2015, November 2009, pp. 37-38.
19 ibid, p. 14.
20 Ergon Energy, PRP1012c Ergon Energy Response to PB.ERG.RRP.08 – Growth Capex, p. 1
21 ibid
22 Ibid.
23 PB notes that confirmation that the Security criteria would not be relaxed was received after submission of Ergon Energy's original regulatory proposal
24 Yarranlea 110/66kV Substation Stage 2 Connection; Blackwater 22kV Regulator Augmentation; West Bundaberg - TF augmentation
25 Ergon Energy, PRP1012c Ergon Energy Response to PB.ERG.RRP.08 – Growth Capex, p. 2.

- in the case of the 2nd 110kV line for Rebuilt Toowoomba Central Sub (140223), the project does not appear in the 2007 SNAPs but does appear in the 2008 SNAP[26] at the page reference identified by Huegin. This indicates that the CIA capex proposal included at least some input from the 2008 planning documentation. Given that the project does not appear in the augmentation plan for 2007, it is unclear how this project, which accounts for 11.4% of the 'New underground 132/66kV cable' augmentation capex, has been included in Ergon Energy's capex forecast

- in the case of the Chumvale sub 2nd 220/66kV TF (DCP17071), comments in the 2007 and 2008 SNAPs[27] note that the constraint will be addressed by a solar thermal power station and therefore the project has not been included in the 10 year augmentation plan. The exclusion of the project from the capex program was confirmed by Ergon Energy with regard to the subsequent 2009 documentation[28] where the treatment is identical to the 2007 SNAP. However, the Huegin reconciliation still includes 1.8 units for this project in the 51.92 units contained in Ergon Energy's capex forecast. Given that this project does not appear in the augmentation plan for 2007or 2008, it is unclear how this project, which accounts for 3.5% of the 'Upgrade (replace) transformers' augmentation capex , has been included in Ergon Energy's capex forecast.

In the majority of cases, PB was still not able to identify the basis for the 'units' included in the Huegin reconciliation in the planning documentation. In particular, the use of partial units for substation or transformer upgrade projects that are not related to projects spanning two regulatory control periods[29] is not transparent and the treatment of partial units for projects with expenditure spanning two regulatory control periods is inconsistent and appears arbitrary[30]. PB sought advice from Ergon Energy on the matter of reconciling the proposed augmentation capex to specific projects in a number of cases[31].

In addition to the direct reconciliation issues outlined above, PB has also noted that the comments for a number of projects in the planning documentation highlight additional concerns regarding the scope, timing, fundamental need and consideration of alternative options.

For example:

- the Miriwini 132/22kV substation project (47916) will be developed by Powerlink. Ergon Energy's scope for substation is identified as a control building, 22kV switchboard and AFLC equipment[32]. However the Huegin reconciliation identifies that the full cost of a

26 Huegin, Review of QLD Draft Determination & Parson Brinkerhoff Report on Ergon Energy's Regulatory Proposal, Version 1.1, January 2010, Appendix A - p.10

27 Ergon Energy, 10 Year SNAP North Queensland Region, November 2007, p.21.

28 Ergon Energy, PRP1014c EE Response to PB ERG RRP 08 Growth Capex_19 Mar 10, p. 4.

29 For example Moonstone 132/22kVA 10MVA Zone Sub (312786) has a commissioning date of December 2012 but only contains 0.2 units in the regulatory control period, The Pialba TF augmentation & 11kV switchboard replacement (50701) contains 2.5 transformer replacements with a commissioning date of November 13

30 For example, 0.4 units have been included in the next regulatory control period for 'Establish Miles Sub' (DCP17775) with a commissioning date of December 2010, yet 1.0 units are included for 'Cairns West 132/22kV substation' (DCP6673) with a commissioning date of November 2015. If a consistent approach were applied, PB would expect either zero units to be included for the Miles Substation or 0.6 units to be included for the Cairns Substation projects.

31 PB Questions: PB.ERG.AS.5 (8 July 2009), PB.ERG.AS.19 (8 July 2009), PB.ERG.AS.86 (30 July 2009) and PB.ERG.AS.112 (7 August 2009) and discussion at meetings 6 August 2009,

32 Ergon Energy, 10 Year SNAP Far North Region, November 2007, p.23.

'New 25MVA Urban Zone Substation' has been included in Ergon Energy's capex proposal[33].

- the need and timing of the Gracemere Zone substation scheduled for November 2013 (and included in Ergon Energy's proposed capex) is not well established and it is clear that limited assessment of the required timing or alternative options has been undertaken based on the comments such as *"A likely option to address emerging issues in the Gracemere and Stanwell areas is to establish a new Gracemere zone substation… … Distribution studies of the area will be required to establish the optimum path forward in this area."*[34] and *"Gracemere area is developing quickly & there is limited existing capacity in the area. Maybe re-build Malchi sub to a large sub instead. Needs planning study."*[35]

- there is uncertainty between Ergon Energy and Huegin with regard to the units included in the proposed capex. For example a full unit is included in the Huegin reconciliation for the 'Establish new Townsville Central Zone Substation' project (168242), however, when queried regarding the apparent uncertainty of the statement *"The timing for Townsville Central sub will depend somewhat on the progress of the Southbank Townsville and the need for load relief to Hermit Park sub but it is envisaged that it will be required by about 2014/15"*[36] Ergon Energy advised that only *"A percentage of funding was allocated in the 2007 SNAPS"*[37].

Noting these inconsistencies and issues and that 5 of the 81 sub- transmission projects (5.8%) identified in the Huegin reconciliation are not supported by the 2007 planning documentation, PB remains of the view that the capex forecast does not reasonably reconcile with either the 2007 or 2008 sub-transmission planning documentation provided with Ergon Energy's original regulatory proposal.

PB reconciliation of 2007 project timing with 2009 SNAPs

In response to PB's enquiries regarding these matters as part of our review of the revised CIA capex[38], Ergon Energy provided a copy of the most recent 2009 SNAP, which was developed using the same security criteria interpretation as the 2007 SNAP. Ergon Energy stated that there appeared to be a strong degree of correlation between the 2007 and 2009 documents[39].

Regarding the demand forecast underpinning the capital programs, Ergon Energy states:

> *"…the demand forecast used to develop the capital expenditure proposal was the 2007 spatial demand forecast. This demand forecast was reconciled with the 2007 top-down forecast prepared by NIEIR and no significant discrepancies were encountered."*[40]

and

33 Huegin Consulting Group, 2010, *"Review of Qld Draft Determination & Parsons Brinckerhoff Report on Ergon Energy's Regulatory Proposal"*, Appendix A - p.7, January 2010
34 Ergon Energy, 10 Year SNAP Capricornia Region, November 2007, p.16.
35 ibid. p. 37.
36 Ergon Energy, 10 Year SNAP North Queensland Region, November 2007, p.17.
37 Ergon Energy, PRP1014c Ergon Energy Response to PB.ERG.RRP.08 Growth Capex_19Mar10, p. 3.
38 PB, Question for Ergon Energy – Growth Capex v3, 3 March 2010
39 Ergon Energy, Draft EE Response to PB.ERG.RRP.08 – Growth Capex, email, 12 March 2010
40 Ergon Energy, Revised Regulatory Proposal, p.106.

> *"Since it submitted its June2009 Regulatory Proposal, Ergon Energy has conducted its 2009 bottom up spatial demand forecast and has reconciled this with the December 2009 top-down maximum demand forecast prepared by NIEIR. The 2009 spatial forecast shows a marginal decrease on that forecast in 2007; however it is still significantly higher than that proposed by the AER and MMA."*[41]

Given Ergon Energy's advice that the 2009 demand forecast is materially the same as the 2007 forecast on which the regulatory proposal has been developed, and noting the application of common security criteria, PB would expect a high degree of correlation at a sub-transmission level where the greater diversification of load typically enables more accurate medium term forecasting of constraints.

PB examined, through a sampling process, the three categories included in the Huegin reconciliation for 2007, 2008 and 2009 to test Ergon Energy's assertion that there was a strong degree of correlation between the 2007 and 2009 documents.

PB found that the majority of the projects included in the 2007 documentation were also included in the 2009 documentation, however, the timing of the projects in the 2009 documentation was more closely aligned to the 2008 SNAP than the 2007 SNAP used to develop Ergon Energy's regulatory proposal, such that their timing was well beyond the end of the next regulatory control period. Specifically, in all three categories tested, PB found that projects that were included in the 2010/11 – 2014/15 regulatory control period under the 2007 SNAP have been deferred significantly, with only 39 of the 86 projects reconciled by Huegin (45%) included in the next regulatory control period under the 2009 documentation. In addition, 41 of the 86 projects reconciled by Huegin (48%) have been deferred beyond the next regulatory control period under the 2009 documentation with:

- 11 of the 86 projects (13%) now scheduled between 2020 and 2030; and,
- 8 of the 86 projects (9%) now scheduled between 2030 and 2040.

Given the deferral of 22% of the projects included in Huegin's reconciliation beyond the subsequent 2015/16 – 2019/20 regulatory control period in the 2009 SNAP, and recognising similar planning criteria and demand forecast drivers are applicable, PB considers that the 2007 SNAP does not reflect the likely timing of projects based on the latest information and therefore does not form a reasonable basis for the capex forecast. Furthermore, whilst recognising that changes in the location of growth across the network can have an influence on expenditure requirements, PB is somewhat surprised at the significant departure in the timing and nature of projects presented by Ergon Energy when comparing the 2007 and 2009 scenarios. PB has noted that only 6% projects in the sample are reconciled in both value (+/-10%) and timing (falling within the period) between the 2007 and 2009 versions.

In comparison to the 41 deferred projects in the sample, PB identified 5 projects[42] that have moved into the next regulatory control period from later commissioning dates in the 2007 SNAP. A review of the planning documentation indicated that one project[43] has been brought forward due to changes in customer requirements, and one has been brought forward as a

41 ibid

42 Serene Valley Substation; Cawdor 2 x 32MVA 33/11kV zone substation; Maryborough North - Establish new Z6-20 ZS; Kumbia ZS establishment; Karumba - Establish 66/22kV substation.

43 Karumba - Establish 66/22kV substation.

replacement for another project[44]. Comments for the remaining three projects indicate that there is still considerable uncertainty with regard to timing[45] or scope[46] or that the project has been deferred by a potentially inefficient temporary solution commissioned in 2009/10 due to 'budgetary constraints' during the current regulatory control period[47]. We note that a permanent substation is now scheduled for construction in 2013.

On this basis, the scope of the 2009 SNAP is poorly supported, and further project deferrals or alternative projects appear to be likely following more detailed consideration of timing, alternative options and fundamental need. Therefore, in PB's view the 2009 SNAP also does not represent a reasonable basis for Ergon Energy's capex forecast for the next regulatory control period.

Ergon Energy reconciliation of 2007 project timing with 2009 SNAPs

As part of subsequent advice provided by Ergon Energy when advised of PB's continuing inability to reconcile the SNAP projects with the expenditure requirements, Ergon Energy also undertook a reconciliation of all of the 266 projects included in the 2009 SNAP with the 2007 documentation for the next regulatory control period. Whilst no further reconciliation of 'units' associated with the projects has been provided, Ergon Energy concluded that[48]:

- 95 projects in the proposed 2009 CIA Capex program also appear in the 2007 SNAP for the next regulatory control period (35.7%)
- 95 projects that were expected to be completed in the current regulatory control period have subsequently been deferred and are now included in the next regulatory control period (35.7%)
- 6 projects scheduled for dates beyond June 2015 in the 2007 SNAP have been brought forward into the next regulatory control period (2.3%)
- 70 additional projects have been identified for the next regulatory control period since the preparation of the 2007 SNAP due to unforeseen changes in local customer or demand forecasts or alternative solutions to existing problems (26.3%).

PB accepts Ergon Energy's analysis, and we note that the high degree of deferral, the small number of projects brought forward, and the low degree of alignment of projects falling within the next regulatory control period, is consistent with PB's findings as set out in the previous section. We also note that Ergon Energy has not identified the number of projects that have been brought forward from the next regulatory control period into the current regulatory control period.

Ergon Energy's findings are summarised in Figure 2.1, below.

44 'Maryborough North - Establish new Z6-20 ZS' project replaces 141557 - new switchboard and control building ($6.1m, Jun10) and brings forward $17.86m Maryborough North ZS establishment (141634 from 2020).

45 'Serene Valley Substation' "*The timing for this sub is uncertain but it has been put into the plan for 2015, with the timing to be reviewed each year*" (2009 Northern Region SNAP p.17.).

46 'Kumbia ZS establishment-141629' *"Required to supply new PQ Hails Ck sub. Alternative 11kV option being considered"* (2009 Wide Bay Region SNAP p.28.).

47 'Cawdor 2 x 32MVA 33/11kV zone substation' *"A project has been approved to establish a new 2 x 20MVA 33/11kV zone substation at Highfields to be called Cawdor Zone Sub (a Highfields sub already exists) by Jul-08… …Due to Capital Works budget constraints, consideration is being given to establishing Cawdor sub as a 10MVA skid mount sub initially, with the permanent zone sub to replace the skid mount when the budget allows."* (2007 South West Region SNAP p.8.).

48 Ergon Energy, PRP1012c Ergon Energy Response to PB.ERG.RRP.08 – Growth Capex, p. 2.

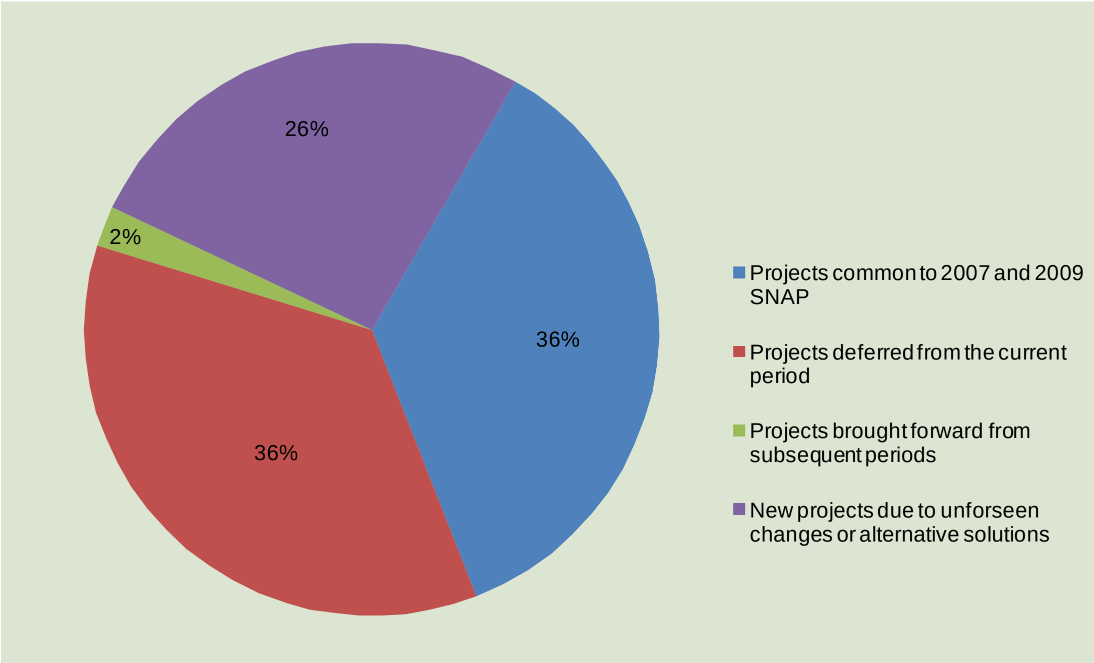

Figure 2.1 2009 sub-transmission augmentation portfolio composition (by number of projects)

Source: PRP1012c Ergon Energy Response to PB.ERG.RRP.08 – Growth Capex, p.2.

Ergon Energy has also identify that there are a further 69 projects with commissioning dates falling in the 2 year period after June 2015 that would have a portion of their works in the next regulatory control period ‘ based on project durations and commissioning dates’. PB notes that despite inconsistencies in application, the use of partial ‘units’ in the Huegin’s reconciliation, and the prior inclusion of 7 projects containing commissioning dates between June and December 2015, was intended to account for this effect in Ergon Energy’s original proposal. The subsequent addition of partial expenditure for projects with uncertain commissioning dates to June 2017 would therefore appear to be inconsistent with Ergon Energy’s previous approach.

Given the significant changes between the 2007 and 2009 planning documentation, which are stated by Ergon Energy to have been prepared on the basis of the same security criteria[49] and notably the same aggregate demand forecast[50], PB is of the view that the large deferrals result from the insufficient consideration of project timing or alternative options in the planning stage of sub-transmission projects. In particular, the lack of preliminary business cases, or similar documentation, to inform medium term planning decisions appears to have had a material influence on the variability and volatility of the expected composition of Ergon Energy’s capital program over the next regulatory control period - with only a 35.7% correlation between the 2007 and 2009 capital program. We note that even this figure is based on whether the project is within the five year period, and not necessarily whether the timing is the same.

This view is further supported by Ergon Energy’s statement that the 70 ‘additional’ projects in the 2009 SNAPs include, in addition to unforeseen changes to local demand or customer base, ‘alternative solutions to existing problems (for example an upgrade rather than expansion)’[51]. That is, changes to, or redefinition of, a previously included project following

49 Ergon Energy, 10 year Sub-Transmission Network Augmentation Plans 2009, December 2009, Section 3.1 (various pages for each of the six regions).

50 Ergon Energy, Revised Regulatory Proposal, p. 106.

51 Ergon Energy, PRP1012c Ergon Energy Response to PB.ERG.RRP.08 – Growth Capex, p. 2.

more detailed consideration of alternative options. Within these 70 projects[52] PB notes the following examples that demonstrate changes arising from the subsequent consideration of alternative options, or that the alternative options have not yet been adequately investigated:

"To improve capacity, QoS & reliability in the Miles area. Existing network comprises long 33kV lines & multiple 33kV regulators. Removes the need to re-build the Rywung fdr" (Columboola 33kV Network Reinforcement)

"New line required to maintain supply to Moorvale when part of existing Moorvale line is re-energised to 132kV (PQ project). Will not be required if PQ builds its own 132kV line." (Moorvale - Build 3km 66kV SCCP line - 00293938)

"maybe use std modular 2 x 25MVA sub" (Cawdor 2 x 32MVA 33/11kV zone substation)

"Line will provide N-1 66kV capacity to Dallarnil. Line will actually run from Isis to Dallarnil." (Childers-Dallarnil 66kV line replacement – 183596)

From our partial review of these 70 projects, we believe that the significant deferrals, the changes of scope, and the subsequent identification of potential alternative options that have not been previously investigated, demonstrate that the projects included by Ergon Energy to support its original CIA forecasts have not been subject to an efficient forward planning and options analysis process. PB has also found a number of projects identified by Ergon Energy as "new projects that do not appear in the 2007 SNAP" that do in fact appear in these documents. For example:

- The $20m Cawdor Zone Substation Project from the 2009 documentation appears to be included in the $55m project in the 2007 SNAP[53] to "Establish Mt Kynoch 110/66kV BSP & establish Cawdor, Meringandan & Crows Nest zone subs as 66/11kV."

- The $20m 'Broxburn sub rebuild' (316573) project from the 2009 documentation appears to replace the $8m 'Pittsworth Zone Substation' included in the 2007 documentation that would *"replace overloaded & aged Broxburn & Yarranlea South zone subs"*[54] and that in 2011 Broxburn substation load would be transferred "*to proposed new Westbrook & Pittsworth subs*" and Broxburn would be decommissioned.[55]

- The $24m 'Pandoin to Keppel DC 132kV Line' (DCP17837) and the $18m 'Keppel New Bulk Supply Sub' (DCP17838) project from the 2009 documentation with a December 2012 commissioning date, appear as current projects in the 2007 documentation with the note that firm feeder capacity will be exceeded in 2009 and the comment that the project *"has been through the regulatory test and received approval from the regulator… …The installation of the Keppel 132/66kV bulk supply substation and its associated 132kV line is scheduled for completion as soon after October 2009 as budget constraints allow*."[56]

- The $18.5m 'Childers-Dallarnil 66kV line replacement' (183596) in the 2009 documentation with a November 2012 commissioning date brings forward the

52 Ergon Energy, *PRP1013c_EE Response to PB ERG RRP08 Growth Capex_SNAP Masterfile 2009_19Mar10_Reformat.xls*, Sheet '09 SNAP in Reg Period', rows 43, 78, 156, 208.
53 Ergon Energy, 10 Year SNAP South West Region, November 2007, p.52.
54 Ergon Energy, 10 Year SNAP South West Region, November 2007, p.48.
55 Ibid p. 27.
56 Ergon Energy, 10 Year SNAP Capricornia Region, November 2007, p.10.

alternative $15.7m 'Isis-Dallarnil - Rebuild 66kV line as 132kV' project in the 2007 documentation from November 2022.[57]

Together, the planning estimates for these four projects account for approximately $101m of the $207m (49%) total planning estimates identified by Ergon Energy for the 70 'Projects not recorded in 2007 SNAPs'[58]. Given that these projects represent substitute projects, project deferrals or both, it is clear that the proposed 'new project' expenditure relates largely to existing projects and existing issues rather than unexpected emerging network constraints. Hence PB is of the view that the number of 'new projects' identified by Ergon Energy is likely to be overstated.

In conclusion, PB considers that neither the 2007 nor 2009 sub-transmission planning documentation reconcile with the capital expenditure in the context of the timing, value, and scope of projects. Therefore neither set of documents can be considered to provide an efficient basis for the capital program.

PB recommendation

Given the demonstrated volatility of Ergon Energy's capital planning and the demonstrated history of deferring large proportions of capital expenditure, PB considers that there are still a significant number of proposed projects included in the 2009 planning documentation that are likely to be deferred following more complete investigation of the fundamental need, timing, alternative options, and scope. Under Ergon Energy's existing processes, this will not occur until closer to the forecast commissioning date for each project. Consideration of planning options at this time may force the business to act inefficiently by adopting short term temporary solutions that may be more costly in the longer term, or imprudently by allowing identified constraints to remain unaddressed due to insufficient allocation of capital resources at the time that the need arises. The temporary use of a skid mount substation to defer the Cawdor Zone Substation augmentation project and the deferral of the Keppel BSP Project due to budgetary constraints are indicative of this issue.

On this basis PB is unable to conclude that Ergon Energy's proposed sub-transmission CIA capex represents prudent and efficient expenditure. Therefore we recommend that an adjustment be applied to Ergon Energy's proposed (2007 SNAP) sub-transmission CIA expenditure to reflect a prudent and efficient level of CIA capex over the next regulatory control period.

At a total of $969.9m, the sub-transmission capex comprises 46.7% of the total $2,076.3 CIA expenditure. Through our reconciliation of the three sub-transmission categories included in the Huegin report with the timing contained in the most recent and relevant planning documentation provided to the AER, PB considered $616.5m (64%) of the proposed $969.9m sub-transmission CIA capex[59]. Despite materially the same demand forecast and security criteria being used, PB found that 45% of the reconciled projects are no longer expected to be required in the period. In addition, Ergon Energy's own reconciliation of its 2007 and 2009 planning documents demonstrates that 62% of the projects now proposed for the period under the 2009 documentation are not included in the capex forecast that underpins Ergon Energy's original or revised regulatory proposal. The majority of the

57 Ergon Energy, 10 Year SNAP Wide Bay Region, November 2007, p.35.

58 Ergon Energy, *PRP1013c_EE Response to PB ERG RRP 08 Growth Capex_SNAP Masterfile 2009_19Mar10_REFORMAT.xls*, Sheet '09 SNAP in Reg Period'.

59 Obtained by excluding all non-CIA expenditure in the Revised SC Capex Data Model and adding the categories: 'Overhead Sub-transmission Lines' ($253.8m), 'Underground Sub-transmission Cables' ($114.8m), 'Substation Bays' ($347.5m), 'Substation Establishment' ($114.5m) and 'Zone Transformers' ($139.3m).

proposed capex therefore represents projects that have been deferred, abandoned, or an alternative project substituted following a more complete consideration of alternative options.

As shown in Table 2.2, PB has found that for the three sub-transmission costing templates assessed, comprising 64% of the total proposed (2007 SNAP) sub-transmission augmentation capex portfolio, a total of $285m of projects are deferred based on the standard unit costs contained in the SC Capex Data Model. PB also identified five '25MVA Zone Substation' projects that were brought forward into the next period from subsequent dates in the 2007 documentation[60]. To make a conservative allowance for a sixth project identified by Ergon Energy as having been brought forward into the period under the 2009 planning documents, PB has included an additional 25MVA Zone Substation unit which represents the highest unit cost item in the SC Capex Data Model[61].

Table 2.2 Sub-transmission augmentation project deferrals 2007 to 2009

	2007 SNAP		2009 SNAP		Difference	
Costing Template	Units	Cost ($m)	Units	Cost ($m)	Units	Cost ($m)
25 MVA Urban Zone Substation	37.1	376.3	19.0	192.7	(18.1)	(183.6)
Underground 132/66kV Sub-transmission line 1km long	52.3	114.1	42.8	93.4	(9.5)	(20.7)
Upgrade (replace) Transformers and associated works	51.92	126.2	18.7	45.5	(33.22)	(80.7)
Total		616.5		331.5		(285.0)
Additional 25MVA Urban Zone Substations			6.0	60.9	6.0	60.9
Total		616.5		392.4		(224.1)

Source: PB analysis.

PB's analysis in Table 2.2 indicates that $224.1m (36.4%) of the $616.5m sub-transmission CIA capex considered by Huegin is no longer supported by the most recent and relevant planning information provided. PB also identified a similar magnitude of unsupported projects when the timing of the projects identified by Huegin was compared with the 2008 sub-transmission planning documents provided with Ergon Energy's original regulatory proposal[62].

Due to the clear interrelation of the sub-transmission projects considered by PB with projects in other costing templates that were not considered (e.g. sub-transmission lines to serve a new zone substation), and noting the high volatility implicit in Ergon Energy's planning processes[63], PB's findings provide little certainty regarding the actual timing or scope of the proposed projects, and PB considers that similar issues are expected across the remainder of the proposed sub-transmission CIA capex.

60 Serene Valley Substation (Dec 2017), Cawdor 2 x 32MVA 33/11kV zone substation (Dec 2016), Maryborough North - Establish new Z6-20 ZS (Nov 2020), Kumbia ZS establishment (Nov 2019), Karumba - Establish 66/22kV substation (Nov 2016).

61 Ergon Energy, Revised Submission_SCCapex Data Model.xls

62 PB provided a list of seven example projects that fell outside the period under the 2008 SNAP. Ergon Energy confirmed that all seven example projects remain outside the period under the 2009 SNAP - refer Ergon Energy, PRP1014c EE Response to PB ERG RRP 08 Growth Capex_19 Mar 10, pp.1-2.

63 62% of the portfolio proposed for the next period has changed from 2007 to 2009 through deferrals, substitute projects or identification of previously unplanned constraints.

Therefore, in relation to projects deferred and brought forward between the next regulatory control period and subsequent regulatory control periods, and as informed by the analysis presented in Table 2.2, PB recommends that a 36.4% reduction is applied across the total of Ergon Energy's proposed sub-transmission CIA capex, as shown in Table 2.3.

In addition, Ergon Energy has advised that 95 of the 265 projects now forecast for the next regulatory control period have been deferred from the current regulatory period. Ergon Energy's analysis[64] identifies 93 projects included in the portfolio with 2007 planning estimates for these projects totalling $165.0m.

PB notes Ergon Energy's statement that:

> *"The number of units are determined from the scope of the project and the SC Capex Data Model applies a unit rate based on a separate list of costs for certain equipment regardless of the project estimate in the SNAP."*[65]

That is, the proposed CIA capex is based on the unit rates set out in the SC Capex Data Model for each asset type, and not on the planning estimates. As it is the planning estimates and not the SC Capex unit rate estimates that are available for these 93 deferred projects, an adjustment is required in order to account for the impact of the 93 deferred projects. From PB's analysis of the three sub-transmission categories identified in the Huegin report, we have found that a total of $596.3m expenditure was supported by the 2007 SNAP based on the SC Capex unit costs. The corresponding 2007 planning estimates for these projects totals $825.7m. Hence, at a high level the SC Capex unit rate estimates are approximately 72.2% (i.e. $596.3m / $825.7m) of the planning estimates.

In order to account for the 93 deferred projects in 2007 SC Capex unit rate terms, PB has multiplied the $165.0m identified from Ergon Energy's analysis of the planning estimates by the 72.2% This results in an additional $119.1m adjustment for projects moving into the next period from the current period. PB considers that this adjustment is representative of the upper limit of the value of the deferred projects, as no corresponding adjustment has been made to account for projects being brought forward from the next regulatory control period into the current regulatory control period. PB's recommended adjustment for projects deferred from the current regulatory period is shown in Table 2.3.

With regards to PB's recommended sub-transmission capex adjustment, we note that the adjustment is based on a high level, top down approach, which has been adopted in the absence of sufficient information from Ergon Energy to apply a detailed bottom-up approach. Nonetheless, PB is of the view that our approach results in a reasonable estimate of the likely impact of the changes being assessed in the absence of more specific information.

64 Ergon Energy, PRP1013c_EE Response to PB ERG RRP 08 Growth Capex_SNAP Masterfile 2009_19Mar10_REFORMAT.xls, '09 SNAP in Reg Period" sheet

65 Ergon Energy, PRP1014c_EE Response to PB ERG RRP 08 Growth Capex_19Mar10, p. 2.

Table 2.3 Recommended sub-transmission CIA capex adjustment

Expenditure category	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Sub-transmission proportion of CIA capex (46.7%)	127.7	166.2	197.6	227.9	250.5	969.9
Adjustment for deferrals beyond the next period (36.4%)	(46.4)	(60.4)	(71.8)	(82.9)	(91.1)	(352.7)
Adjustment for deferrals from the current period.	15.7	20.4	24.3	28.0	30.8	119.1
PB total sub-transmission adjustment	(30.7)	(40.0)	(47.6)	(54.9)	(60.3)	(233.5)
PB recommendation	96.9	126.2	150.0	173.0	190.2	736.4

Note: totals may not add due to rounding.
Source: PB analysis.

Distribution augmentation reconciliation

PB also conducted an assessment of the degree of project deferral within the Distribution Network Augmentation Plan (DNAP) between 2007 and 2008 to test the extent to which further analysis of the 2009 documentation would be required. PB examined 118 projects and identified that 7 projects had been deferred outside the regulatory control period based on the 2008 documentation. In addition, the deferral periods were noted to be much less than observed in the SNAP documentation with typical deferrals in the order of 1 to 2 years in comparison to the 15-20 year deferrals noted at a sub-transmission level.

Notwithstanding the above, PB notes that whilst the derivation of the number of 'units' included for each project was more transparent in the DNAP spreadsheets, the project descriptions generally do not identify the actual scope of the project to allow a comprehensive reconciliation of planning units to the capital forecast.

On the basis of the much smaller degree of project deferral noted in the 2007 DNAP documentation, PB does not consider that project deferrals are material at a distribution level and therefore recommends no adjustment on this basis.

Forecast adjustment

PB has recalculated the 18 month (30%) forecast adjustment having regard for the deferral of the forecast recommended by MMA and taking the midpoint of the range of non-forecast driven CIA capex of 70.9% advised in the Huegin report. This results in a recommended value of $1,450.8m for CIA capex, an average of $290.2m per annum, across the next regulatory control period. Due to the steep annual growth in CIA capex proposed by Ergon Energy and the effect of the deferral adjustment, a direct scaling of the proposed capex does not provide realistic distribution of expenditure over the period, with expenditure unfavourably weighted towards the latter years. Therefore an alternative high level approach has been adopted for Ergon Energy in order to provide a more realistic spread of expenditure across the period. To arrive at an annual adjustment, PB has spread the adjustment across the period in accordance with the long term linear growth trend in CIA capex of $20.5m per year over the period 2001/02 to 2009/10 as shown in Figure 2.2.

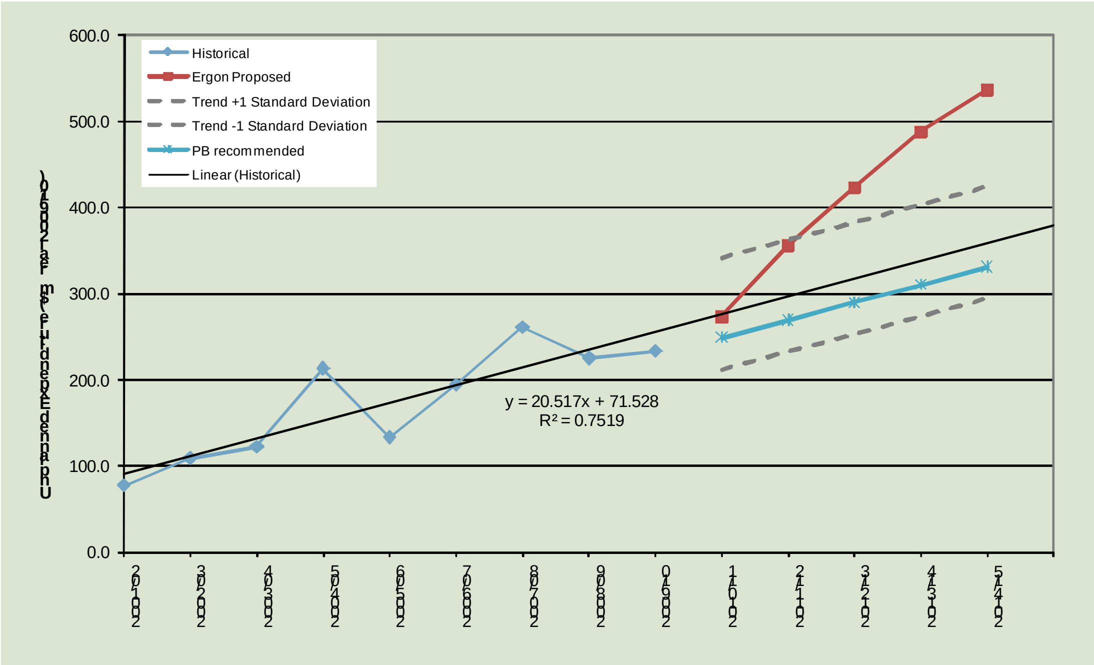

Figure 2.2 Historical and Proposed CIA Capex

Source: PB analysis.

PB notes that accounting for the recommended $625.5m adjustments, the CIA capex amount of $1,450.8m represents a 33% real increase over the $1,093m historical CIA capex identified by Ergon Energy for the current regulatory control period in its revised regulatory proposal. PB's recommended CIA capex is shown in Table 2.4.

Table 2.4 Recommended forecast adjustment capex

Expenditure category	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy revised proposal	273.3	355.8	423.0	487.9	536.3	2,076.3
Less Sub- transmission Adjustment	(30.7)	(40.0)	(47.6)	(54.9)	(60.3)	(233.5)
Subtotal CIA Capex	242.6	315.8	375.4	433.0	476.0	1,842.8
Proportion of growth capex related to the demand forecast (i.e. 70.9%)	172.0	223.9	266.2	307.0	337.5	1,306.5
PB adjustment - 18 month deferral (i.e.30% reduction to demand driven growth capex)	6.6	(46.1)	(85.3)	(122.3)	(144.8)	(392.0)
PB recommendation	249.1	269.6	290.2	310.7	331.2	1,450.8

Note: totals may not add due to rounding.
Source: PB analysis.

Essentially, the adjustments set out in Table 2.4 consist firstly of the application of the sub-transmission adjustment as discussed above, then the adjustment for the impact of the revised forecast. That is, the sub-transmission adjustment has been applied first to arrive at a CIA capex value that is adjusted to account for the identified reconciliation issues. However, as the resulting CIA capex is based on Ergon Energy's forecast, this must then be adjusted to account for the demand forecast revision proposed by MMA. Hence, the forecast adjustment is applied to the CIA capex once adjusted for the identified reconciliation issues have been taken into account.

Conclusion

PB has reviewed Ergon Energy's revised proposal, and we have concluded that the new and additional information provided does not demonstrate that the revised CIA capex proposal is prudent and efficient. Consequently, PB recommends that the AER apply the adjustments shown in Table 2.5 to Ergon Energy's revised proposal to account for the likelihood of ongoing deferral of subtransmission development projects, and to account for the impact of reduced aggregate demand forecasts as informed by the MMA review.

Table 2.5 Recommended CIA capex

Expenditure category	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy revised proposal	273.3	355.8	423.0	487.9	536.3	2,076.3
Sub-transmission CIA capex deferral – ref Table 2.3	(30.7)	(40.0)	(47.6)	(54.9)	(60.3)	(233.5)
PB adjustment - 18 month deferral (i.e. 30% reduction to demand driven growth capex) – ref Table 2.4	6.6	(46.1)	(85.3)	(122.3)	(144.8)	(392.0)
PB recommendation	249.1	269.6	290.2	310.7	331.2	1,450.8

Note: totals may not add due to rounding.

Source: PB analysis.

2.2 Customer initiated capex – forecast methodology

PB is required to review in detail, and provide advice on the prudence and efficiency of the revised customer initiated capital works expenditures proposed in section 10.4.3 of Ergon Energy's revised proposal.

In its original proposal, Ergon Energy proposed a total of $1,695.0m for customer initiated capital works (CICW) in the next regulatory control period. Following a detailed review, the AER did not accept Ergon Energy's demand forecasts, and in its draft decision made a downward adjustment of $318.1m.

In making its draft decision, the AER considered that the robustness of Ergon Energy's forecast CICW capex was not supported by Ergon Energy's forecasting methodology.

In its report, PB concluded that Ergon Energy's application of NIEIR dwelling stock growth forecasts to forecast growth in future commercial and industrial connections was not appropriate as no correlation or causation between the two values had been demonstrated. PB also did not consider that dwelling stock growth would be a good predictor of rural customer connections, and that gross regional product is not well correlated to large CICW connections and is therefore not a good predictor of this class of customer connection numbers.

As Ergon Energy was unable to provide any evidence to substantiate its view that there was a correlation between the CICW baseline expenditure, dwelling stock growth and gross regional product, PB constructed a model based upon the historical number of customer connections. This model averaged the number of new customers over the last regulatory control period and increased this by the expected annual growth. Based on this methodology, PB recommended a reduction in the proposed CICW expenditure of $318.1m.

The AER rejected Ergon Energy's forecast on the basis of PB's concerns and proposed that the expenditure should be reduced in line with PB's analysis.

2.2.1 Revised proposal and new information

Ergon Energy's revised proposal is for CICW expenditure of $1,846.5m. This is some $151.5m higher than the original proposal of $1,695.0m.

In its revised proposal Ergon Energy asserts that the dwelling stock growth forecasts are appropriate to forecast growth in commercial and industrial connection expenditure. Ergon Energy states that it tested the assumption using historical data and concluded there was a strong relationship between dwelling stock growth and rural connection expenditure and that it was appropriate to use dwelling stock growth as a forecast driver for domestic and rural CICW expenditure[66].

Ergon Energy further states that it:

> *"tested the assumption that GRP influences large commercial and industrial connections. Ergon Energy could not demonstrate a strong correlation between large CICW and GRP. Investigation revealed that changes in the realisation and the spread of connection projects over several years render the correlation weak.*
>
> *Ergon Energy have revised their forecast methodology for large CICW and have recalculated large CICW based on dwelling stock growth due to the correlation between overall commercial and industrial expenditure and dwelling stock.*[67]"

Ergon Energy's revised proposal therefore also used dwelling stock growth as the forecast driver for all CICW expenditure and its revised expenditure figures are calculated on this basis.

Ergon Energy also employed Huegin to undertake a review of its original forecast to see whether dwelling stock numbers and gross regional product were appropriate measures to use as forecasts for CICW growth. Huegin's key findings with regard to Ergon Energy's forecast methodology were that:

> *"Ergon Energy's assumptions regarding dwelling stock growth as a predictor of future commercial and industrial expenditure is reasonable;*
>
> *Ergon Energy's forecast for commercial and industrial expenditure is validated by independent analysis that shows the total expenditure in the next regulatory period represents a robust forecast;*
>
> *The fact that Ergon Energy's historical growth has been in coastal areas has no relevance to the NIEIR dwelling stock growth forecast for the total Ergon network area and no bearing on the Ergon Energy forecast for domestic and rural connection expenditure. Further, independent analysis again demonstrated that Ergon Energy's domestic and rural connection expenditure forecast is reasonable;*"

and

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66 Ergon Energy Corporation Limited, 14 January 2010, *"Revised Regulatory Proposal to the Australian Energy Regulator. Distribution Services for 1 July 2010 to 30 June 2010"*. Section 10.4.3.3.2 p.109.

67 ibid. Section 10.4.3.3.4 p.110.

> *"Large CICW expenditure is difficult to forecast due to the uncertainty of the nature and timing of major projects, however Huegin considers that the Ergon Energy method of using actual potential projects adjusted by probability of occurrence is suitable (and notes that it is similar to other DNSP approaches, e.g. ETSA). An adjustment for expenditure not realised of $19m against the plan in FY09 should, however, be made*."[68]

PB notes that Ergon Energy did not rely on this last finding in its revised proposal but instead used dwelling stock as a driver for large CICW as noted above.

2.2.2 PB findings and recommendation

PB has reviewed Ergon Energy's revised proposal and the supporting material provided. Our review of the issues raised by Ergon Energy in relation to CICW proposal as set out in the revised proposal is addressed in the following sections.

Dwelling stock as a driver for commercial & industrial connections

PB does not believe that the analysis undertaken by Huegin demonstrates that dwelling stock forecasts are necessarily an appropriate driver for forecasts of CICW expenditure on future industrial and commercial connections.

In section 3.5.1 of its report, Huegin undertakes three separate analyses to test the application of NIEIR dwelling stock growth forecasts to commercial and industrial connections.

The first analysis (presented in its Figure 3.5) shows a relationship between domestic & rural connection expenditure and small commercial and industrial expenditure based on the five years of data available from Ergon Energy. Huegin rightly have apprehensions about using this analysis to confer that dwelling stock growth infers causation of industrial and commercial connections. PB agrees that there is insufficient data to draw a strong conclusion from this analysis.

The second piece of analysis undertaken used an external data source – the Construction Forecasting Council's 'non-residential construction value' - for Queensland (minus Brisbane) and plotted this against Ergon Energy's small C&I connection expenditure.

Huegin's conclusion was that

> *"the expenditure on small commercial and industrial connections by Ergon Energy is proportionate to the value of non-residential construction in Queensland excluding Brisbane*[69]*".*

PB notes that this analysis does not demonstrate that dwelling stock is a good driver of commercial and industrial connections. Rather, it argues that Ergon Energy should use non-residential construction, as opposed to residential construction as a driver for the commercial and industrial connection forecasts.

The Huegin report appears to make the recommendation that a non-residential database be used instead of dwelling stock. *"Huegin considers that this external data source provides an*

68 Huegin Consulting Group, 2020, *"Review of QLD Draft Determination & Parsons Brinkerhoff Report on Ergon Energy's Regulatory Proposal",* p39

69 Huegin Consulting Group, 2020, *"Review of QLD Draft Determination & Parsons Brinkerhoff Report on Ergon Energy's Regulatory Proposal",* p26

alternative forecast test basis for Ergon Energy's small commercial and industrial expenditure[70].

Huegin's final analysis takes the Construction Forecasting Council's data for QLD (ex Brisbane) non-residential construction value data (actual and forecast) and applies this growth rate to Ergon Energy's FY2008 small commercial and industrial connection costs to develop another forecast of connection expenditure.

Huegin imply that because a separate forecast based on a different method broadly aligns with the results of Ergon Energy's forecast that this means that Ergon Energy's forecasting method must be reasonable. As Huegin has not demonstrated that the two approaches to forecasting growth move together or offered evidence to show that the apparent correlation would continue into the future, PB recommends caution in using the Construction Forecasting Council's data to validate Ergon Energy's forecasts.

PB therefore disagrees that Ergon Energy's consultants have demonstrated a causality between dwelling stock growth forecasts and commercial and industrial connections.

Dwelling stock as a driver for rural connections

PB's second concern with Ergon Energy's forecasting methodology was the application of dwelling stock forecasts to rural customer connections. This was because Ergon Energy's most significant growth has occurred in specific regional centres (notably coastal).

Huegin's report discusses this point and concludes that the fact that Ergon Energy's most significant growth is occurring in specific regional areas has no relevance to the independent NIEIR dwelling stock growth forecasts and has no bearing on the Ergon Energy forecast for domestic and rural expenditure. PB accepts this view, however, PB notes that this view does not provide verification that dwelling stock is appropriate to use as a driver for overall customer connections.

Gross regional product as a driver for large customer connections

PB's third concern with Ergon Energy's forecasting model was the application of gross regional product as a driver for large CICW connections.

Huegin considers the assumption that large CICW connections would be related to GRP is a reasonable starting point, but:

> "*the nature of accounting processes and time periods over which expenditure occurs and is measured is unlikely to align with financial years. In this sense, Huegin agrees with PB that gross regional product is not well correlated to large CICW connections*"[71].

Huegin further noted that it:

> *"did observe a differential between the estimated expenditure in FY09 and the actual recorded expenditure for large CICW connections of $19m. This differential appears to be the result of a lower realisation of planned major projects due to delays most likely caused by the recent financial crisis. These delays are precisely the type of event that disrupts the GRP to large CICW expenditure correlation. Huegin considers that it would*

70 Ibid p 27

71 Huegin Consulting Group, 2020, *"Review of QLD Draft Determination & Parsons Brinkerhoff Report on Ergon Energy's Regulatory Proposal",* p32

> *be prudent for Ergon Energy to remove this $19m from the overall forecast for large CICW expenditure"*[72].

Huegin's findings confirm PB's conclusion that Ergon Energy did not demonstrate that regional GDP should be used as an appropriate driver in its large CICW expenditure forecasts.

Ergon Energy's revised proposal

Ergon Energy's revised proposal for CICW expenditure is based on the application of NIEIR's dwelling stock forecast growth for all categories of customer connections including large CICW connections.

Despite PB's concerns with using this growth forecast for small CICW connection, Ergon Energy has provided no basis for using this approach for large connections. PB notes that Huegin did not discuss or propose this growth rate as suitable for large connections.

In Ergon Energy's CICW Forecasts document RP937c the rational for the revised forecast methodology is set out:

> *"Ergon Energy forecast all categories of CICW expenditure using dwelling stock growth as the driver. This was based on analysis which demonstrated a good correlation between dwelling stock growth and CICW expenditure (both for individual categories and total of CICW expenditure)*[73].

Furthermore Ergon Energy's methodology highlights some of the limitations of its approach:

> *"It is noted that correlation analysis was hampered by a lack of significant sample set of historical data for expenditure and new connections. Ergon Energy has less than ten years of annual historical data for CICW which is a very limited sample set for the purpose of undertaking rigorous correlation analysis.*
>
> *Domestic and Rural connections were taken as a proxy for past dwelling stock changes as Ergon Energy does not record actual historical dwelling stock growth data for its distribution area and hence does not have precise data available. It was found that the correlation between Domestic and Rural connections and CICW expenditure was strong enough over the period 2001-02 to 2007-08 to justify using those connections as a driver for future CICW expenditure levels*[74]"

PB does not believe that the methodology described by Ergon Energy adequately demonstrates causality between dwelling stock growth and large connection growth.

Specifically, Ergon Energy's correlation analysis contained in its CICW forecasts document RP937c merely demonstrates that the total cost of connections increases with the number of connections.

Based on the supporting information, the effect of Ergon Energy changing its forecasting driver from GRP to dwelling stock for large connections appears to have increased the proposed CICW expenditure requirement by $151.5m. While part of this increase is due to Ergon Energy's revised escalators and overheads calculation, given the magnitude of this

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72 Ibid. p.33.

73 Ergon Energy, 06 December2009, "Forecasts Customer Initiated Capital Works – Standard Control Services" section 6.3.1 p.31.

74 Ibid.

effect, PB would expect to see stronger evidence that the cost of connecting large customers is related to dwelling stock growth. PB considers that the amount of analysis and justification provided by Ergon Energy is insufficient given the large expenditure increase proposed.

PB does not believe that Ergon Energy has adequately demonstrated causality and, as in its previous report, is unable to conclude that the revised expenditure proposal for CICW is prudent and efficient.

PB's original modelling

In its revised proposal, Ergon Energy criticises the model developed by PB.

Ergon Energy engaged Huegin to review the PB forecast model and methodology. The results of that review are included in Document RP938c and summarised below:

- the connection numbers used by PB are incorrect, representing an $80m error in its forecast
- the accuracy that PB claim for its average connection cost is reliant upon comparison against the first two years of Ergon Energy's forecast that PB have recommended that the AER not accept
- a more appropriate average connection cost input in the PB model results in a forecast significantly closer to Ergon Energy's forecast
- the PB forecast is at the very low end of the range of forecasts assessed by Huegin[75].

In its original review, PB stated that insufficient supporting data was available from Ergon Energy to justify the original CICW forecasts and PB was therefore unable to conclude that the proposed CICW capex was efficient. Because of this finding, in making a recommendation to the AER, PB developed an alternative model. PB notes and accepts some degree of criticism levelled by Huegin of the model.

PB's model was simplistic given the limited data available to derive an alternative model and focussed on information contained within Ergon energy's original RIN submission templates. PB did not have access to macro-economic data and did not have time to develop a comprehensive connection cost forecast based on different customer classes and hence the model has a coarse resolution and will, by nature, be sensitive to input changes. In particular, Huegin state that

> *"… repeatedly smoothing out variances in actual data over time and across heterogeneous cost groupings cannot be considered to represent business-as-usual. The cost to connect a customer to the Ergon Energy network ranges from the thousands of dollars for a subdivision or domestic and rural connection to the millions of dollars for a large commercial or industrial connection. Ergon Energy have factored in this variation through identification of drivers of the individual connection category expenditure. PB have removed this level of rigour by applying an average connection cost across categories and time"*[76].

75 Ergon Energy Corporation Limited, 14 January 2010, *"Revised Regulatory Proposal to the Australian Energy Regulator. Distribution Services for 1 July 2010 to 30 June 2010"*. Section 10.4.3.3.4 p 111

76 Huegin Consulting Group, 2020, *"Review of QLD Draft Determination & Parsons Brinkerhoff Report on Ergon Energy's Regulatory Proposal",* p 33

PB believes that this criticism equally applies to Ergon Energy's revised proposal. Huegin's assertion is that Ergon Energy is able to capture the range of network connection costs in its model by applying different drivers to different individual connection category expenditure. PB notes that Ergon Energy only identified two drivers – dwelling stock and gross regional product. In its revised proposal, Ergon Energy has reduced the number of drivers downward and now applies the dwelling stock growth to all CICW categories. Ergon Energy effectively now only has one driver of connection expenditure in its model and in PB's view any rigour identified by Huegin has now been removed from Ergon Energy's proposals.

For reasons discussed earlier, PB cannot confirm that the new proposed CICW expenditure is efficient.

PB's original model with corrected figures

In its initial review of the CICW proposals, PB identified that Ergon Energy had quoted different numbers for customer connections and on several occasions asked Ergon Energy to verify the correct data.

Ergon Energy's response to our queries was contained in two emails:

- Ergon Energy Response to AER-PB Q.AS97. AS.121 & AS.137 - CICW Historical Expenditure, 19 August 2009;
- Ergon Energy Response to AER-PB Q.AS.142 - Follow-Up to AS.140 (and AS.97, AS.121 & AS.137) - Customer Numbers, 29 August 2009 respectively.

The first of these emails contained a disclaimer that Ergon Energy could not validate the accuracy of the historical information contained in them. PB subsequently asked Ergon Energy to explain why the figures provided were substantially different from the customer numbers submitted as part of its original RIN submission. Ergon Energy's response in the second email corrected some of the customer connection numbers previously provided and contained a reconciliation of the RIN figures with these new corrected figures. The email also contained an explanation that Ergon Energy's computer systems do not keep a record of changes in connection status.

PB accepts that it did not incorporate the information provided in the second mail correcting connection figures. Huegin's report contains two tables 3.5 and 3.6 which outline PB's original analysis and Huegin's analysis based on the corrected figures. These tables are replicated below as Table 2.6.

Table 2.6 Data from PB's CICW model and Huegin's analysis

PB Model	FY05	FY06	FY07	FY08	FY09
CICW Capex ($m 09/10)	$65.84	$222.04	$309.68	$294.60	$275.29
Total Connections	29,039	30,983	29,330	30,097	30,137
Average cost per connection	$2,267	$7,167	$10,558	$9,788	$9,135
Huegin Analysis	**FY05**	**FY06**	**FY07**	**FY08**	**FY09**
CICW Capex ($m 09/10)	$202.00	$243.65	$315.03	$305.42	$296.66
Total Connections	26,334	27,155	27,365	29,839	26,416
Average cost per connection	$7,671	$8,973	$11,512	$10,235	$11,230

Source: PB analysis.

Having subsequently reviewed the two emails from Ergon Energy, PB can now replicate Huegin's figures for total connections as those identified as a correction by Ergon Energy in its 29 August email and can reconcile the figures for CICW Capex as those contained in Ergon Energy's email of 19 August (adjusted to real 09/10 dollars). PB is satisfied that these updated figures should have been used as the inputs to our original model. Critically, we note the major increase in FY05 for the CICW capex figure and suggest this change will have the largest impact on the model's result.

Huegin provide three scenarios of the impact of data error:

- if the actual historical connection numbers are substituted into the PB model, and the 2008-09 actual average cost of a connection ($11,230) is used, the PB model produces a total CICW forecast of $1,616m. This is $240m higher than PB's recommended substitute forecast that the AER has accepted in the draft decision; or

- if the actual historical connections numbers are substituted into the PB model, and the average of the last four years average connection costs are used (Huegin does not consider that the average connection cost for 2004-05 is relevant as this data is from the previous regulatory period), the PB model produces a total CICW forecast of $1,582m. This is $205m higher than PB's recommended substitute forecast that the AER has accepted in the draft decision; or

- even using PB's model and methodology as presented, simply substituting the actual connection number and expenditure data in as provided by Ergon Energy produces an average cost of connection of $10,230 and a subsequent CICW forecast of $1,456m. This is $80m higher than PB's recommendation[77].

Of the three outcomes identified by Huegin, PB would recommend that the AER approves CICW expenditure using the third scenario. This is because this calculation uses the maximum of the available data for the average cost of customer connection on a real 2009-10 basis and represents a longer-run average. The first calculation relies only in one year's data, which could be influenced by short-term specific factors which may not be

77 Huegin Consulting Group, 2020, *"Review of QLD Draft Determination & Parsons Brinkerhoff Report on Ergon Energy's Regulatory Proposal",* p 34 & 35

relevant to future costs. PB does not agree that data for the 2004-05 regulatory control period should be regarded as irrelevant especially given the limited range of data available.

PB has re-run its model based on the correct figures over the five year period. This results in an increased allowance of $67.3m.

PB notes that Huegin does not agree with the methodology of averaging connection costs over time, but given the limited data available PB is unable to offer an alternative model. PB is not in a position to formulate an extensive connection cost forecasting model based on different customer classes and believes the onus for this ultimately rests with the business to support its expenditure forecast. In its original report, PB sought to independently test Ergon Energy's CICW forecast and constructed a model based on the historical number of customer connections and historical cost of customer connections. The model averages the number of new customers over the last regulatory control period and increases this number by the expected annual growth. PB accepts some of the limitations of this model highlighted in the Huegin report, however PB considers no new and substantive information has been provided as part of Ergon Energy's revised proposal to suggest a more reasonable or detailed approach is achievable. PB maintains its view that the resultant CICW will provide a prudent and efficient level of expenditure to ensure future customer connection activities at levels consistent with Ergon Energy's recent historical experience.

Conclusion

On the basis of Ergon Energy's revised proposal, and the analysis outlined above, PB recommends the revised customer initiated capital works expenditure as set out in Table 2.7.

Table 2.7 PB recommendation – customer initiated capital works - growth capex

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Ergon Energy revised proposed	363.7	394.7	341.8	357.3	389.0	1,846.5
PB adjustment	(73.9)	(103.2)	(56.5)	(68.4)	(100.4)	(402.3)
PB recommendation	289.8	291.6	285.3	288.9	288.6	1,444.2

Source: PB analysis.

PB notes that Huegin recommends that the forecast for large CICW should also be reduced by $19m due to 2009 projects not being realised. This would reduce the total recommended CICW from $1,444.2m to $1,425.2m.

2.3 Asset replacement capex - methodology

PB is required to review in detail, and provide advice on the prudence and efficiency of the resubmitted asset replacement capex proposed in section 10.4.4 of Ergon Energy's revised proposal.

In its original proposal, Ergon Energy proposed a total of $1,214.1m for asset replacement capex over the next regulatory control period. This represents a real increase of 72% over expenditure in the current regulatory control period.

Following a detailed review, the AER did not accept Ergon Energy's asset replacement capex proposal, and in its draft decision made an adjustment of $118.8 million to reflect a business-as-usual level of expenditure. In making its draft decision, the AER had regard to PB's advice that we were unable to conclude that Ergon Energy's proposed replacement capex is prudent and efficient. This was based on PB's view that Ergon Energy's replacement capex forecasts rely on (in part) the application of an aged based approach, and that Ergon Energy was unable to provide sufficient information to demonstrate the basis for its forecast replacement volumes (with the exception of the underground cables and joints replacement program)[78]. Consequently, the AER considered that Ergon Energy had not demonstrated that its forecast replacement capex is prudent and efficient.

2.3.1 Revised proposal and new information

In its revised proposal, Ergon Energy has rejected the AER's draft decision, and submitted a forecast expenditure of $1,256.4 m, which represents its original proposal adjusted to account for changes in cost escalators and the reallocation of overheads. This revised proposal is based on additional work undertaken to support the original forecasts.

In its revised proposal Ergon Energy sets out a number of arguments to support its revised replacement capex proposal, and has provided supporting reports prepared by its consultant Huegin. In summary, Ergon Energy argues that[79]:

- it does not use an age based approach to asset replacement
- the forecast in its original proposal is prudent and efficient
- adjustments to an entire category based on assessing four categories of expenditure cannot be supported
- the application of a business-as-usual level of expenditure will have unacceptable consequences in terms of performance (customer service) and safety (employee and public).

In arguing that it replaces assets based on condition, Ergon Energy provided an outline of its two main asset replacement programs, and notes that the NARMCOS asset replacement forecasts are based on the asset population and known historical defect rates from asset inspections. Ergon Energy further notes that where condition is unknown, asset age is used for financial forecasting purposes, but is not used as the basis for asset replacement[80]. Ergon Energy points to Huegin's conclusions that the most appropriate maintenance method is used given the assets and circumstances, that age is used to forecast replacement volumes rather than for identifying assets to be replaced, and that assets are replaced based on condition[81].

Ergon Energy further argues that the application of a business-as-usual level of expenditure to an entire category based on assessing four categories of expenditure cannot be supported. Essentially, Ergon Energy states that assessing four categories of expenditure as the basis for such an adjustment is logically and statistically flawed. Ergon Energy notes that the logical flaw is that a statistical test was applied without the statement of a hypothesis,

78 PB, *"Review of Ergon Energy regulatory proposal for the period July 2010 to June 2015"*, pp.54-55, 24 November 2009.
79 Ergon Energy Corporation Limited, 2010, *"Confidential Revised Regulatory Proposal to the Australian Energy Regulator, Distribution Services for 1 July 2010 to 30 June 2015"*, p. 113, 14 January 2010.
80 ibid. p.114.
81 ibid.

while the statistical flaw is that the adjustment is based on one program from a sample of four drawn from a population of 26, and that this would return results accurate to 25% +/- 39.8%. Hence the error is greater than the test result[82].

Huegin's report also question the assumption that a business-as-usual level of spending is appropriate give that a continuing under spend on replacement capital is evident from[83]:

- the QCA's last determination which noted that there had been under-investment and increased replacement capex
- Ergon Energy's continued under spend in the current regulatory control period due to unforeseen network growth requirements
- SAHA's benchmarking which shows that replacement capex is historically under spent
- analysis of the RIN data which shows historical depreciation has been 56% higher than replacement capex - indicating a possible significant historical under spend.

Ergon Energy's revised proposal also includes a review of three of the four replacement categories originally reviewed. Specifically, the reviews address the Pole Top Replacement Program, the Conductor and Connector Replacement Program, and the Zone Substation Transformer Replacement program.

With regards to the Pole Top Replacement Program, Ergon Energy argues that its proposed forecast is based on a revised program introduced because the current (business-as-usual) approach is critically flawed and does not deliver the required level of reliability[84]. It is further argued that the revised program is based on two separate studies, that the associated operating expenditure was approved, only high risk pole tops are targeted, and that the inspection program has been shown to uncover higher defect rates.

Ergon Energy engaged Huegin to examine the pole tops replacement forecasts and notes Huegin's finding that the pole top maintenance method is appropriate. Huegin also reiterated that the earlier studies[85] found that high rainfall areas with aged poles as areas of risk to be addressed. With respect to the Elevated Work Platform (EWP) inspection program, Huegin noted the increased pole top defect rate, and considered the applicability of the results beyond the Far North region, arguing that in terms of the average rainfall and average humidity, the Far North is not dissimilar on a regional level to Mackay and North Queensland; regions where annual rainfall exceeds 900mm. Huegin concluded the results of these earlier studies could be scaled for use beyond Far North Queensland, further noting that the statistical significance the results of these earlier studies show that the rate of pole top unserviceability *"could be expected to be between 3.2% and 6.8%"*[86] for pole tops in the Far North[87].

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82 ibid. p.115.

83 Huegin Consulting Group, 2010, *"Review of Qld Draft Determination & Parsons Brinckerhoff Report on Ergon Energy's Regulatory Proposal"*, p. 46, 18 January 2010.

84 Ergon Energy Corporation Limited, 2010, *"Confidential Revised Regulatory Proposal to the Australian Energy Regulator, Distribution Services for 1 July 2010 to 30 June 2015"*, p. 115, 14 January 2010.

85 Ergon Energy, *"Distribution Pole Head Rot Management Project"*, Noonan and Brooks, and PL738c_EE_EWP Inspection Defects between 1Jul06 & 30Jun07_20Aug09

86 Huegin Consulting Group, 2010, *"Review of Qld Draft Determination & Parsons Brinckerhoff Report on Ergon Energy's Regulatory Proposal"*, p.50, 18 January 2010.

87 ibid. pp. 49-51.

In relation to the Conductor and Connector Replacement Program, Ergon Energy submitted a revised strategy[88], which provides specific information regarding the forecast replacement volumes. In addition the strategy highlights that:

- 5.7% of Ergon Energy's conductor assets are over 50 years of age, and without any replacement, 10.57% will exceed 50 year of age by 2015
- small diameter Hard Drawn Bare Copper (HDBC) over 50 years of age has a high probability of failure, and that 3.11% of the high voltage distribution network conductor and 12.7% of the sub-transmission network conductor is HDBC - much of which is aged
- it proposes to replace 1.3% of the installed conductor length over the next regulatory control period.

Ergon Energy engaged Huegin to review its conductor and connector proposal. In this review Huegin concludes that lifecycle based volume forecasting is appropriate, and that Ergon Energy undertakes asset replacement on a defect and condition basis. To support these points Huegin argues that[89]:

- any inference that Ergon Energy replaces connectors and conductors based on age is incorrect, as Ergon Energy does not possess knowledge of the age of the installed conductor population, or specific quantities by type
- the forecast replacement volumes are based upon known mean lifecycle as well as the installed population base, and that this is the most appropriate method given the available knowledge
- Ergon Energy's forecast is for the volume of assets likely to be replaced, and this does not mean that assets are replace based on age, rather they are replaced based on their condition as determined during inspections
- the proposed replacement rates of 1% for 66kV and 0.7% for 132/110kV is conservative given the expected mean life (not age) of 50 years.

Ergon Energy's revised proposal also provides a review of the zone substation transformer replacement capex. Ergon Energy restates that 26 failures have occurred over the past two years, 12 of which were due to winding failures, and notes that it is moving to a proactive program of transformer management which includes dry-outs and replacement prior to failure. Ergon Energy goes on to note that it has a comprehensive routine oil sampling program, as well as maintenance and inspection programs, and that these form the basis of its equipment maintenance, refurbishment and replacement.

In its review Ergon Energy argues that PB's conclusion that there was no information provided to substantiate the volume forecasts for replacement transformer capex is incorrect, and that the document PL783c details condition assessments for 445 power transformers requiring intervention. Ergon Energy also points to PB's concern regarding historical failure rates, and the proposed dry-out program volumes, as evidence that Ergon Energy does have a significant transformer management issue.

88 Ergon Energy, 2010, *"Connector Maintenance and Refurbishment Strategy"*, Ref. RP941c, 11 January 2010.

89 Huegin Consulting Group, 2010, *"Review of Qld Draft Determination & Parsons Brinckerhoff Report on Ergon Energy's Regulatory Proposal"*, pp.52-54, 18 January 2010.

Finally, Ergon Energy refers to Huegin's modelling of its transformer fleet, which is based on the current condition of the fleet, coupled with known failure rates. Huegin's model predicts the degradation of the transformer fleet over time, indicating a greater number of events than Ergon Energy's original proposal. Huegin concludes that the proposed replacement capital is likely to be insufficient for the next regulatory period. Ergon Energy also argues that as it is resource constrained and unable to undertake the higher levels of replacement predicted by Huegin's model, but concludes that a business-as-usual level of expenditure will *"… pose a significant risk to Ergon Energy due to the higher probability of transformer failure that will result"*[90].

2.3.2 PB findings and recommendation

PB has reviewed Ergon Energy's revised proposal and the supporting material provided. Our review of the issues raised by Ergon Energy in relation to its asset replacement capex proposal as set out in the revised proposal is addressed in the following sections.

The basis of asset replacement forecasts

In our review of Ergon Energy's original replacement capex, PB concluded that Ergon Energy had not demonstrated the prudence and efficiency of its forecast replacement volumes. Moreover, PB noted that Ergon Energy's forecasts are (in part) based on asset age, and in our opinion this is not good practice as it implicitly ignores the assets condition and operational context, hence leads to an inefficient forecast[91].

Ergon Energy argues that it "… *does not use an age based approach to asset replacement*"[92], and that assets are replaced based on their condition. Ergon Energy also states that the NARMCOS asset replacement forecasts are based on the asset population and known historical defect rates; adding that where condition is unknown, asset age is used for financial forecasting purposes[93]. Huegin also found that *"Age is used to forecast replacement volumes rather than for identifying assets to be replaced"*[94]. While PB accepts that in practice Ergon Energy makes replacement decisions based on performance and condition, Huegin's statements confirm PB's concerns of over forecasting expenditures due to the use of age in the financial modelling, which we noted in our first review[95].

We also note that in its revised proposal, Ergon Energy has submitted additional material in relation to specific replacement programs. This material is reviewed in the following sections.

Business as usual expenditure

Ergon Energy argues that the application of the business-as-usual level of expenditure adjustments to an entire category based on assessing four categories of expenditure cannot be supported. A number of issues are raised in support of this view, these are discussed below.

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90 Ergon Energy Corporation Limited, 2010, *"Confidential Revised Regulatory Proposal to the Australian Energy Regulator, Distribution Services for 1 July 2010 to 30 June 2015"*, p. 115, 14 January 2010.

91 PB, *"Review of Ergon Energy regulatory proposal for the period July 2010 to June 2015"*, pp.54-55, 24 November 2009.

92 Ergon Energy Corporation Limited, 2010, *"Confidential Revised Regulatory Proposal to the Australian Energy Regulator, Distribution Services for 1 July 2010 to 30 June 2015"*, p. 113, 14 January 2010.

93 ibid. p. 114.

94 ibid. p. 113.

95 PB, *"Review of Ergon Energy regulatory proposal for the period July 2010 to June 2015"*, p. 54, 24 November 2009.

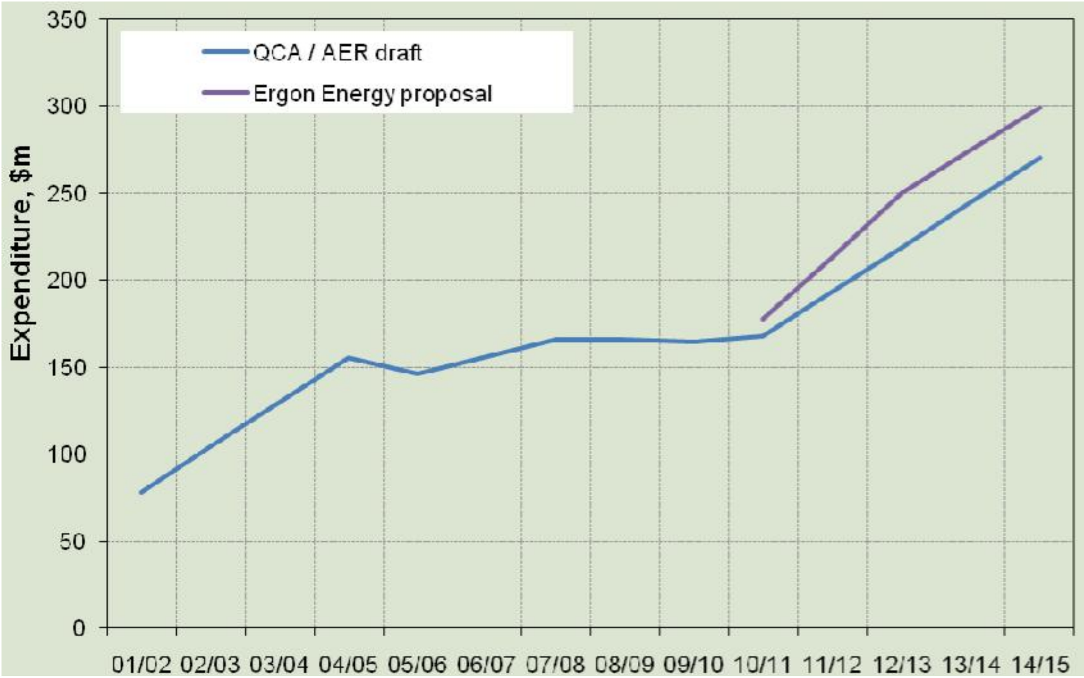
Ergon Energy considers that the test applied is logically and statistically flawed[96]. PB disagrees with this point, as it incorrectly assumes that the business-as-usual level of expenditure adjustment was determined from a statistical test based on the sample reviewed. This is not the case. Rather, having reviewed 48% of the proposed asset replacement capex and found that in our view Ergon Energy had not reasonably demonstrated the prudence and efficient of their proposed capex, PB sought to identify a benchmark level of capex that represents a prudent and efficient level of expenditure for Ergon Energy. Hence, PB used Ergon Energy's historical business-as-usual level of asset replacement capex as the benchmark. In PB's view, as the QCA had reviewed and approved Ergon Energy's capex for the current period, and reviewed and accepted a high level of expenditure in the previous period, it is likely that the expenditure history reasonably represents a prudent and efficient level of expenditure.

PB notes that Huegin argues further, that Ergon Energy has historically under spent replacement capex and that this was recognised by the QCA in its last determination. Huegin also notes that replacement capex has been under spent in the current regulatory period as shown by benchmarking and RIN analysis, and concludes that a business-as-usual level of spending is inappropriate in terms of prudence and efficiency as a continuing under spend on replacement capital is evident.

While PB recommended a business-as-usual level of expenditure, this was determined using the observable historical growth trend across the 2001/02-2004/05 period. We note that the historical growth trend for replacement capex is explainable in terms of Ergon Energy's amalgamation history, and that this expenditure growth was addressed in the QCA's last review. PB used this trend in calculating the business-as-usual expenditure to 'smooth out' the volatility of the historical expenditure. This trending can be seen in Figure 2.3 which shows a comparison of Ergon Energy's replacement capex proposal and the QCA approved and AER draft determination replacement capex. PB is of the view that by adopting this growth trend approach, Ergon Energy's historical under expenditure is reasonably accommodated within the forecast trend. This can be seen by considering the total long-run investment in asset replacement, which totals $2.41b between 2001/02 and 2014/15 under Ergon Energy's proposed expenditure level, compared to $2.36b based on the QCA approved investment and the AER's draft determination. Hence, the difference in the long run investment is 1.7% below that proposed by Ergon Energy. Moreover, PB notes that while Ergon Energy's proposed replacement capex represents a real increase of approximately 72% over the current period, the business-as-usual capex in the context of the longer term average nonetheless represents a real increase of 55% over the current period.

96 Ergon Energy Corporation Limited, 2010, *"Confidential Revised Regulatory Proposal to the Australian Energy Regulator, Distribution Services for 1 July 2010 to 30 June 2015"*, p. 115, 14 January 2010.

Figure 2.3 Long term replacement capex comparison



Source: PB analysis.

While Ergon Energy argues that there has been significant historical under expenditure on asset replacement, in PB's view, the method used in determining the business-as-usual level of expenditure reasonably accounts for this under spend.

Specific reviews

In its revised proposal, Ergon Energy has included a review of three of the four asset categories previously reviewed by PB. These are discussed below.

Specific reviews – pole top replacement

In relation to the Pole Top Replacement Program, Ergon Energy argues its proposed forecast is based on a revised program which has been implemented as the current (business-as-usual) approach is critically flawed and does not deliver the required level of reliability[97]. Ergon Energy further notes that only high risk pole tops are being targeted, and higher defect rates have been demonstrated. In support of this Huegin argues that the results of these studies are statistically significant, indicating a pole top unserviceability rate of between 3.2% and 6.8%"[98], which Huegin argues can be scaled for use beyond Far North Queensland.

In PB's previous review of the pole top replacement program, we noted that Ergon Energy's network asset equipment plan for pole top structures states that forecast failure rates would remain consistent with current defect rates with some allowance for additional defects. We also noted Ergon Energy's advice that this program targets only high risk areas and that only a very small quantity of distribution inspections (45,133) is being undertaken[99]. Further, in

97 ibid.

98 Huegin Consulting Group, 2010, *"Review of Qld Draft Determination & Parsons Brinckerhoff Report on Ergon Energy's Regulatory Proposal"*, p.50, 18 January 2010.

99 Ergon Energy response to questions AS.102, AS.115 and AS.125 21/08/09.

examining Ergon Energy's Asset Management Strategy Document[100], we noted its analysis, which concluded that Ergon Energy's performance compares favourably with industry averages, and demonstrated that the HV crossarm reliability is consistently above benchmark levels[101].

PB has reviewed the "Distribution Pole Head Rot Management Project" report that was included with Ergon Energy's revised proposal. While this report concludes (in part) that the " *… rate of identification of crossarm and pole head defects from the groundline inspection is sufficiently low to support the introduction of a specialised pole top inspection process for some poles."*[102], PB did not identify any analysis to support the conclusion that the current (business-as-usual) approach is critically flawed and does not deliver the required level of reliability. Moreover, as discussed above, the information and analysis presented in Ergon Energy's network asset equipment plan and in particular the Asset Management Strategy Document does not appear to support the conclusion that the current (business-as-usual) approach is critically flawed.

Ergon Energy has also argued that it is only targeting high risk pole tops and that two separate reports and Huegin's analysis supports a statistically significant higher failure rate. Noting that Huegin is of the view that 26% of the candidate pole tops were found to either have defects or be unserviceable, and that Huegin notes repair rates of 6.9% with replacement rates at 20.2%[103], PB re-examined the application of the defect rates in the NARMCOS model.

In re-examining the NARMCOS model PB notes that this model contains few formula, and that most information consists of 'fixed' numerical values. Consequently, as we noted in our previous review, the relationships within the model are not readily apparent. However, we note that the higher defect rates have been applied to the Elevated Work Platform Pole Top Repair, Elevated Work Platform Pole Top Replacement, High Risk Dist. Detail Pole Top Assembly Repair, High Risk Dist. Detail Pole Top Assembly Replacement, Sub-Trans Pole Top Assembly Repair, and Sub-Trans Pole Top Assembly Replacement categories.

The NARMCOS model also shows that the number of pole top inspections associated with the higher defect rate is approximately 119,000 over the next regulatory control period. PB notes that Ergon Energy plans to replace approximately 43,000 pole tops under this program, which implies a defect rate of 36%. Taking Huegin's point, that 26% of the candidate pole tops were found to either have defects or be unserviceable[104], implies that approximately 31,000 pole tops are to be replaced. Alternatively, if 43,000 pole tops are to be replaced, then this implies inspection of approximately 165,000 pole tops. From our review of the NARMCOS model, PB is of the view that the pole top section of the model is inconsistent with the documentation provided, in particular, with Ergon Energy's relevant asset equipment plan and asset management strategy.

Having re-examined the NARMCOS model we have found that, even if the higher defect rates are accepted as reasonable estimates of the expected defects, the information in the NARMCOS model does not appear to reconcile, and the basis of the replacement volume forecasts within the NARMCOS model is not apparent.

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100 Ergon Energy, 2009, *"Network maintenance asset management strategy document: asset maintenance strategy"*, Version 0.8 final, April 2009.

101 PB, *"Review of Ergon Energy regulatory proposal for the period July 2010 to June 2015"*, pp. 45-47, 24 November 2009.

102 Ergon Energy, *"Distribution Pole Head Rot Management Project*", p. 12.

103 Huegin Consulting Group, 2010, *"Review of Qld Draft Determination & Parsons Brinckerhoff Report on Ergon Energy's Regulatory Proposal*", p.50, 18 January 2010.

104 ibid.

Huegin also argues that the pole top defect rates can be scaled for use beyond Far North Queensland. However, we note that Huegin does not propose a scaling method. Moreover, it is not apparent from examination of the NARMCOS model or the supporting documentation that Ergon Energy has adopted a scaled approach, and if so how this scaling has been determined and applied.

Having reviewed the NAMRCOS model, in PB's opinion, the model and supporting documentation do not demonstrate the prudence and efficiency of Ergon Energy's proposed replacement capex.

Specific reviews – conductor and connector replacement

In relation to the Conductor and Connector Replacement Program, in PB's first review of this program, we found that we could not conclude that the proposed capex is prudent or efficient, adding that many of the volume estimates appear to be age-based provisions that are not directly related to defect history or condition assessment. Ergon Energy's revised proposal includes a revised conductor and connector strategy[105], as well as supporting analysis undertaken by Huegin.

PB has reviewed the revised Conductor and Connector Replacement Program and notes that it proposes to replace approximately 1,928 km of conductor, or 1.3% of the installed conductor length over the next regulatory control period[106]. The program document also notes that 5.7% of Ergon Energy's conductor assets are over 50 years of age, and without any replacement 10.57% will exceed 50 year of age by 2015. Furthermore, small diameter Hard Drawn Bare Copper (HDBC) over 50 years of age represents 3.11% of the high voltage distribution network conductor and 12.7% of the sub-transmission network conductor. The appendix of this document also sets out the Conductor and Connector Replacement Program budget allocations from the revised NARMCOS model.

In PB's opinion, while the revised Conductor and Connector Replacement Program document represents approximately 90% of the Conductor and Connector replacement capex proposal ,and sets out much of the basic information associated with the proposed replacement capex, it does not provide demonstration of the prudence and efficiency of the proposed level of capex funding. PB was unable to establish from the supporting document how Ergon Energy has determined that 1,928 km of conductor should be replaced, or that this is the efficient level of replacement.

Huegin argues that Ergon Energy has adopted a lifecycle based volume forecasting approach that is appropriate to Ergon Energy's circumstances[107]. In making this argument Huegin states that any inference that Ergon Energy replaces connectors and conductors based on age is incorrect, as Ergon Energy does not possess knowledge of the age of the installed conductor population, or specific quantities by type. While this may be the case, it is also very clear from the revised Conductor and Connector Replacement Program[108] and from Ergon Energy's Asset Equipment Plan – 04 Conductor & Connectors[109], that Ergon Energy uses year of manufacture data, pole age and sub-transmission line age, as proxies for conductor age in its replacement analysis.

105 Ergon Energy, 2010, "*Connector Maintenance and Refurbishment Strategy",* Ref. RP941c, 11 January 2010.

106 ibid. p. 12.

107 Huegin Consulting Group, 2010, *"Review of Qld Draft Determination & Parsons Brinckerhoff Report on Ergon Energy's Regulatory Proposal*", pp.52-54, 18 January 2010.

108 Ergon Energy, 2010, *"Connector Maintenance and Refurbishment Strategy*", Ref. RP941c, p. 8, 11 January 2010.

109 Ergon Energy 2009, "*Network asset equipment plan 04: conductors & connectors"*, pp. 3-4, 03 April 2009.

Huegin further argue that Ergon Energy forecasts replacement volumes based upon known mean lifecycle and the installed population base, which Huegin considers the most appropriate method given the available knowledge. PB disagrees with this conclusion, and with the view that forecast volumes based on a life expectancy and known asset population is the most appropriate method given the available knowledge. In our view, information such as historical failure rates, defect rates, replacement rates, as well as incident records are also essential to the development of a robust replacement volume forecast. We note that in Ergon Energy's revised Conductor and Connector Replacement Program document that such information is presented. For example, failure rates per 100 km are presented for both steel and hard draw copper conductor. Further to this, we anticipate that Ergon Energy would have records relating to historical replacement volumes that could be used to further demonstrate the reasonableness of the proposed replacement volumes. PB would also anticipate that when preparing a replacement volume forecast that economic assessment and risk assessment[110] would be undertaken to further support the proposed level of expenditure in order to demonstrate that it is the prudent and efficient level of investment.

Having reviewed Ergon Energy's revised Conductor and Connector Replacement capex proposal, PB has found that in our opinion the new information does not demonstrate the prudence or efficiency of the proposed capex.

Specific reviews – zone substation transformer replacement

Ergon Energy's review of its zone substation transformer replacement program restates that recent transformer failure history has involved 26 failures over the past two years, with 12 of these being due to winding failures. In its review, Ergon Energy further notes that it is moving to a proactive program of transformer management, including dry-outs, and replacement prior to failure. In support of its replacement volume forecasts, Ergon Energy also argues that document PL783c provides substantiating details on the condition of 445 power transformers, and refers to Huegin's review which concludes that the proposed replacement capital is likely to be insufficient for the next regulatory period. Ergon Energy notes that as it is resource constrained, it is unable to undertake the higher levels of replacement predicted by Huegin's model, but states that business-as-usual expenditure will *"… pose a significant risk … due to the higher probability of transformer failure that will result"*[111].

In PB's original review of Ergon Energy's zone substation transformer replacement program, PB found that we could not conclude that the proposed transformer replacement capex is prudent or efficient. In this review, PB noted its concerns regarding Ergon Energy's replacement volume forecasts and in particular with the robustness of the supporting information. We also noted concern regarding high historical failure rates, as well as with the unit costs associated with the transformer dry-out program[112].

In relation to Ergon Energy's historical failure rate, Ergon Energy references its documents PL587c and PL835c which were included with its original proposal. In Table 2.8 the information from PL587c relevant to power transformer failures is presented, while Table 2.9 presents the relevant information contained in PL835c. PB agrees with Ergon Energy that these documents contain historical failure information for power transformers, however in our

110 PB notes that the Asset Equipment Plan – 04 Conductor & Connectors document contains a risk assessment, however in our view it does not address the issue of the value of risk, or more specifically the change in the value of risk associated with the proposal to replace approximately 1,928 km of conductor over the next regulatory period.

111 Ergon Energy Corporation Limited, 2010, *"Confidential Revised Regulatory Proposal to the Australian Energy Regulator, Distribution Services for 1 July 2010 to 30 June 2015"*, p. 115, 14 January 2010.

112 PB, *"Review of Ergon Energy regulatory proposal for the period July 2010 to June 2015"*, pp. 50-53, November 2009.

view they provide little insight into historical failure rates, failure trends, analysis of those trends, analysis of the consequences or associated risk[113], or associated management options, etc. Hence in PB's opinion PL587c and PL835c do not contain sufficient information to demonstrate a sound basis for the proposed forecasts.

Table 2.8 Power transformer failure information

Zone Sub Station Assets	No of failures
2007/08	12
2008/09	14
Total for last 4 years	40

Source: Extract from PL587c

Table 2.9 Substation Asset Failure Investigations – 2008 - power transformers

No	Investigation closed	Year made	Month	Comments
1	Allora T2	1985	Nov-08	Trfr tripped due to storm and two fuses blown. Switched back to service after tests confirmed it is good
2	Dalby Stn Trfr	1965	Mar-08	Phase to Phase short circuit on new ABB 25kva transformer
3	Dalby T2		Feb-08	Trfr was scrapped after internal failure
4	Louisa Creek		Oct-08	All 3 Trfr's indicated bad oil results. Trfr's switched out
5	Mica Creek Stn T2	1997	Oct-08	Found an open circuit winding. Trfr replaced
6	Miriamvale T5	1996	Apr-08	Bad oil results forced the Trfr to be switched out. Failed internal.
7	Mossman T1	1963	Nov-08	Trfr trip due to s snake on it
8	Pajingo T2	1977	Oct-08	Oil samples indicate Partial Discharge
9	Glenmore T4	1961	Apr-08	After a fault on the RG-C4 a 11kV capacitor bank the transformer alarmed on bucholtz and there were signs of gas venting
10	West Dalby T2		Nov-08	

Source: Extract from PL835c. Note make and model columns have been omitted for brevity.

Ergon Energy also notes PB's concern that no information was provided to support the volume forecasts for general transformer replacements, and cites the information in document PL783c. PB reviewed this document with Ergon Energy's original proposal and has re-examined the document as part of the revised proposal. PB agrees with Ergon Energy that PL783c contains information on the condition assessments of 444 power transformers, or approximately 70% of Ergon Energy's power transformer fleet.

PB notes that this spreadsheet contains oil, water, insulation, and gas test results, amongst other descriptive data for each power transformer. Within the spreadsheet, a score is assigned to each of the test results, and the transformers are categorised as Replace, WDryout, or SieveMolecular. Table 2.10 provides a summary of the categorisation presented in PL783c, while Table 2.11 summarises the test results that the replacement category is based on.

113 PB notes that the Network Asset Management Plan - 17 Zone Substation Transformers document contains a risk assessment, however in our view it does not address the issue of the risk, or the change in the risk, associated with the proposed capex program.

Table 2.10 Category summary

Category	Count*	Percentage
Replace	34	8
WDryout	245	55
SieveMolecular	165	37
Total	444	100

Source: PB analysis of PL783c.

Table 2.11 Test result summary for replacement category

Test	Count*	Percentage
Oil analysis	8	13
Water analysis	23	38
Insulation age	27	44
IEEE gas	3	5

** Note does not add to 34 replacements as some units are replaced based on multiple test results*

Source: PB analysis of PL783c.

As shown in Table 2.10, PL783c proposes the replacement of 34 power transformers, and we note that this number generally corresponds to the 35 replacements set out in the NARMCOS replacement capex model. The above tables also show that a large proportion of transformers are categorised as WDryout and SieveMolecular, and that a large proportion of replacements are based on water test results.

In Huegin's report (RP939c), it notes that *"Condition data provided to the AER indicates that approximately 445 transformers, or 70% of the population are regularly assessed."*[114] Huegin also sets out the scoring system used in PL783c, noting that a score of 1 is 'OK', a score of 2 is 'Warning', 3 is 'Defect', and 4 requires immediate action. We further note that the scoring in the PL783c spreadsheet shows that approximately 33% of all transformer records have a score of 4 (i.e. require immediate action) associated with one or more of its test results, and approximately 39% have a score of 3 (i.e. defect). This indicates that approximately 72% of the assessed transformers require dry out, molecular sieve, or replace actions.

PL783c also sets out the test dates for each transformer. PB notes that the test dates range from 1999 to 2005 for records with a score of 3 or 4, and from 2000 to 2005 for records with a replacement category. We also note Ergon Energy's advice in relation to this information, which in part states:[115]

> *"This analysis was completed on data extracted in the second half of 2005 and has not been completely refreshed since. However, minimal work has been done on transformer dryouts and replacements other than failures, so this list is still very indicative of the condition of the population of transformers in Ergon Energy's network and on which the forecasts are based."*

114 Huegin Consulting Group, 2010, *"Zone Substation Transformers – A simulation based approach to determining the demand for replacement capex"*, p.5, January 2010.

115 Ergon Energy email, 2009, *"EE Response to AER-PB Q.AS.117 - Power Transformers Condition Assessments"*, 25 August 2009.

In PB's opinion, this outcome does not reflect the regular assessment of 70% of the transformer population, as is suggested by Huegin. In our view, given that each power transformers is a major asset, good electricity industry practice would involve more frequent and careful ongoing monitoring and testing of any power transformer found to be in poor condition. Consequently, with 72% of the assessed transformers requiring immediate action or being recognised with a defect in 2005, it is unclear to PB why no further test results or condition assessment information is available over four years later despite Ergon Energy maintaining that it has a comprehensive routine inspection and oil sampling program which requires oil samples every 2 years[116]. In PB's view, this lack of information may be indicative of the recent high rate of transformer failure, and given that the information is quite dated, its relevance to the current state of the equipment is questionable in our view.

PB also notes Ergon Energy's advice that:[117]

> *"However, before any action is taken a thorough assessment of each transformer will be undertaken to ensure that the appropriate action is taken on both technical and economic grounds."*

We also note that approximately 62% of transformers with a 'replace' classification in PL783c have an associated test date of 2004 or earlier; that is, prior to the QCA's last determination. Given the specific condition issues highlighted by PL783c, and Ergon Energy's technical and economic assessments, it is apparent that Ergon Energy had accepted the risk associated with transformer failure. However, PB notes that Ergon Energy has not supplied any of this analysis to demonstrate that there is a greater risk of transformer failure.

In its revised proposal, Ergon Energy refers to a model develop by Huegin based on the current condition of the fleet, coupled with known failure rates[118]. Based on this model, Huegin concludes that Ergon Energy's proposed replacement capital is likely to be insufficient for the next regulatory control period. PB notes that Huegin's model was not supplied to PB, and hence we are unable to comment on the model itself. However, PB has reviewed Huegin's report, and we note that one key assumption of the model is: [119]

> *"An assumed likelihood of failure of 2% was used for all transformers under all ages and conditions and this does not increase due to degraded condition or decrease due to intervention action."*

As Huegin later notes, this constant 2% failure rate represents an assumed transformer age of 50 years, and that it also approximates Ergon Energy's failure rate of 26 transformers over the last two years out of a population of approximately 640[120]. In PB's opinion, by assuming a 50 year life, the model is more likely to represent an approximation of the expected upper limit of transformer expenditure, as opposed to the expenditure required for the prudent and efficient management of the transformer fleet. Given the criticality of this assumption, and the lack of information to substantiate its validity, PB can not conclude that Huegin's model provides a prudent and efficient forecast of transformer replacement capex.

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116 Ergon Energy, 2009, *"Network Asset Management Plan - 17 Zone Substation Transformers*", p. 11, 31 March 2009.

117 Ergon Energy email, 2009, *"EE Response to AER-PB Q.AS.117 - Power Transformers Condition Assessments"*, 25 August 2009.

118 Ergon Energy Corporation Limited, 2010, *"Confidential Revised Regulatory Proposal to the Australian Energy Regulator, Distribution Services for 1 July 2010 to 30 June 2015"*, p. 120, 14 January 2010.

119 Huegin Consulting Group, 2010, *"Zone Substation Transformers – A simulation based approach to determining the demand for replacement capex"*, p.9, January 2010.

120 ibid. p. 12.

PB has examined the information provided in Ergon Energy's revised proposal in relation to the specific asset replacement categories previously reviewed by PB, and we have found no new or additional information to demonstrate the prudence and efficiency of Ergon Energy's proposed asset replacement capex.

Conclusion

In PB's original review we were concerned with a range of issues, and in particular with the partial use of age based replacement forecasts, as well as the demonstration of defect and replacement rates. While Ergon Energy's revised proposal presents additional material in relation to these issues, in PB's opinion Ergon Energy has not provided any new information to demonstrate that its replacement forecasts are not age based and that the defect and replacement rates reasonably reflect a prudent and efficient replacement volume. Consequently, PB recommends that the AER apply the adjustments shown in Table 2.15 to Ergon Energy's revised proposal.

Table 2.12 Recommended capex for asset replacement capex

Expenditure category	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy revised proposed	181.2	222.6	261.7	285.9	305.03	1,256.4
PB adjustment	(10.0)	(20.2)	(32.5)	(31.2)	(29.3)	(122.9)
PB recommendation	171.2	202.4	229.2	254.7	275.8	1,133.5

Source: PB analysis.

2.4 Reliability and quality capex – justification

PB is required to review in detail, and provide advice on the prudence and efficiency of the resubmitted reliability and quality improvement capex proposed in section 10.4.5 of Ergon Energy's revised proposal.

In its original proposal, Ergon Energy proposed a total of $122.4m of reliability and quality improvement capex for the next regulatory control period. Following a detailed review, the AER did not accept Ergon Energy's reliability and quality improvement capex proposal, and in its draft decision made an adjustment of $35.4m to reasonably reflect the capex criteria and comply with the NER.

In making its draft decision, the AER had regard to PB's advice that there is insufficient information for PB to conclude that the reliability and quality capex was prudent and efficient due to limited economic analysis and insufficient supporting information.

2.4.1 Revised proposal and new information

In its revised proposal, Ergon Energy has rejected the AER's draft decision, and submitted a proposal of $125.0m, which represents its original proposal adjusted to account for changes in cost escalators and the reallocation of overheads. This revised proposal is based on a review of the original assumptions and methodology employed.

In its revised proposal, Ergon Energy argues that the there is no regulatory requirement to report or target a specific number of feeders, and that the reported number of worst performing feeders is not the number of feeders targeted, rather the targeted number of feeders is based on a balance of the identified need and resources[121].

Ergon Energy also maintains that it conducts causal analysis of feeder performance and references a range of supporting documents, noting that the information presented informs the requirement to address the identified performance issue as well as the appropriate action. Ergon Energy also notes that Huegin's review concludes that the causes of poor feeder performance are well recognised by Ergon Energy[122].

With regards to the benefits and timing of the proposed capex, Ergon Energy argues that these are inherent in the feeder improvement program, and are addressed in the Network Management Plan. Further, Ergon Energy note that the timing of these works is dynamic and inherent in project ranking and prioritisation with the best value projects addressed first[123].

Ergon Energy also states that it conditionally agrees that the forecast capex is a provision to address feeder performance, arguing that reliability problems change over time and cannot be definitively scoped ex-ante. Furthermore, Ergon Energy states that it does not consider that duplication of expenditure is possible due to the operation of its planning processes, citing the Network Management Plan's requirement that maintenance and operational solutions are also considered with reliability improvement initiatives. Ergon Energy goes on to note if expenditure is not found to be required on the targeted feeders due to other expenditure, then the funds can be redirected to alternative poor performing feeders[124]. Ergon Energy refers also to Huegin's report which notes that while the proposed expenditure is not specifically targeted, and while Ergon Energy's process are not formally documented, Ergon Energy's[125]:

> *"…proposed process is sufficient to ensure that any expenditure resulting from the FIP will not overlap with any other capital or operating expenditure initiatives."*

Ergon Energy note that the adjustment applied to the Reliability and Quality Improvement capex does not meet the capital expenditure criteria as: its prudence and efficiency has not been assessed; historical expenditure was much lower than planned due to resource reallocation; the likely requirement for reliability improvement expenditure is not accounted for in the method applied; and the method does not consider Ergon Energy's circumstances[126]. Ergon Energy also notes Huegin's benchmarking which shows that Ergon Energy's Reliability and Quality Improvement capex is among the lowest in Australia.

Ergon Energy further argues that with the MSS targets becoming more stringent, it must respond with a capex program that will meet these needs and that the Feeder Improvement Program is based on the gap of feeder performance to MSS targets, as well as prioritised on performance and the number of customers affected[127].

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121 Ergon Energy Corporation Limited, 2010, *"Confidential Revised Regulatory Proposal to the Australian Energy Regulator, Distribution Services for 1 July 2010 to 30 June 2015"*, pp. 123-124, 14 Jan 2010.
122 ibid, p. 124
123 Ibid.
124 ibid, pp. 124-125
125 Huegin Consulting Group, 2010, *"Review of Qld Draft Determination & Parsons Brinckerhoff Report on Ergon Energy's Regulatory Proposal"*, p.61, 12 January 2010. PB notes that in the revised Huegin report dated 18 January 2010 this point has been amended. See Huegin report dated 18 January 2010, p. 65.
126 Ergon Energy Corporation Limited, 2010, *"Confidential Revised Regulatory Proposal to the Australian Energy Regulator, Distribution Services for 1 July 2010 to 30 June 2015"*, pp. 125-126, 14 Jan 2010.
127 ibid.

2.4.2 PB findings and recommendation

PB has reviewed Ergon Energy's revised proposal and the supporting material provided. Our review of the issues raised by Ergon Energy in relation to their reliability and quality improvement proposal as set out in the revised proposal is addressed in the following sections.

A prudent and efficient level of investment

In reviewing the worst performing feeder program, PB noted that there was no demonstration that the top 50 worst performing feeders is the prudent number to target[128]. Ergon Energy argues that: there is no regulatory requirement to report or target a specific number of feeders; that they are targeting 42.5 feeders; and that the targeted number is based on a balance of the identified need and resources[129].

While PB acknowledges that the actual number of feeders to be targeted under this program is 42.5, the primary issue of concern to PB is that in our opinion the available documentation does not demonstrate that investment of $40.2m to address the performance of 42.5 feeders over the next regulatory control period is prudent and efficient. Our concern here is not the number of feeders targeted *per se*, but that this number, and more specifically the proposed investment, is a prudent and efficient level of investment.

PB would anticipate that demonstration of the prudency and efficiency of such a program would involve analysis showing the expected number of non-performing feeders against recognised performance criteria, along with supporting trend and root cause analysis. When supported by appropriate risk analysis and analysis of associated avoidable costs[130], this would form the foundation of an estimated forward volume of work and inform a cost benefit analysis. Where such analysis has been previously undertaken, further analysis showing the realised benefits against historical investment would also support and further inform this analysis. In PB's opinion, a robust analysis of this type would clearly define the need and timing of the proposed investment, would demonstrate the level of investment that is commensurate with the associated benefits, and would inform assessment of the prudence and efficient level of proposed investment.

PB notes that the Evans and Peck report submitted with the revised proposal discusses the feeder improvement program and makes recommendations in relation to the program criteria, as well as level and extent of the program. This report also contains estimates of the customer value of reliability improvements[131]. Section 6 of the feeder improvement document notes SAIDI savings of 21 minutes for improvements to 80 feeders[132]. We also note that the Electricity Industry Code provides for customer payments under Guaranteed Service Levels (GSLs), that there are financial incentives in relation to reliability performance under the Service Target Performance Incentive Scheme (STPIS), and we anticipate that Ergon Energy's has identifiable cost savings associated with the proposed investment. Moreover we note the analysis in Ergon Energy's Annual Network Reliability Performance Reports as well as the Connector Maintenance and Refurbishment Strategy. However, despite the

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128 Parsons Brinckerhoff Australia Pty Limited, 2009, *"Review of Ergon Energy regulatory proposal for the period July 2010 to June 2015"*, p.60, 24 November 2009.

129 Ergon Energy Corporation Limited, 2010, *"Confidential Revised Regulatory Proposal to the Australian Energy Regulator, Distribution Services for 1 July 2010 to 30 June 2015"*, pp. 123-124, 14 January 2010.

130 The costs referred to are the do nothing costs that could be avoided through appropriate investment.

131 Evans & Peck. 2009, "*ENERGEX and Ergon Feeder Improvement Program Review"*, 23 January 2009.

132 PB notes that this addressed both the Generic Feeder Program (not reviewed by PB) and the Worst Performing Feeder Program (reviewed by PB).

availability of such information, Ergon Energy has not provided analysis to demonstrate that the proposed level of investment is the prudent and efficient..

PB also notes that Ergon Energy states that the targeted number is based on a balance of the identified need and resources. However, PB has also been unable to identify Ergon Energy's analysis demonstrating this balance, or whether this balance in itself is a prudent or efficient level of investment.

Investment benefits and timing

In our review of the worst performing feeder improvement program, PB noted that the benefits and timing of the proposed $40.2m expenditure were not identified. In its revised proposal Ergon Energy argues that consideration of the benefits and timing are inherent in the feeder improvement program, noting that these are addressed in the Feeder Improvement Program[133] and Network Management Plan[134]. Further, Ergon Energy note that the timing of these works is dynamic and inherent in project ranking and prioritisation with the best value projects addressed first[135].

PB has reviewed the documentation referenced by Ergon Energy in its revised proposal, and note that this documentation was also reviewed with the original proposal. With regards to the Feeder Improvement Program[136] PB notes that it does address the benefits of the program, but with the exception of SAIDI benefits[137], does so only by identifying the benefits that could in principle be expected from the program with no identification of the value of these benefits. For example, network operation benefits and preventive or corrective maintenance benefits[138]. While PB considers that the SAIDI benefits indentified are considerable, the attribution of these savings to the proposed capex, the scope of work required to achieve these savings, and the timing of the savings are not apparent in relation to the capex being proposed. We note that some of the approaches to achieving these SAIDI savings are noted in the program document, however again they are general descriptions of types of works such as replacement of newly found equipment failures, installation of sectionalisers, and installation of spreaders, rather than specific items that would support reasonable engineering-based program estimating.

With regards to the Network Management Plan, we were unable to identify any benefits relevant to the proposed capex, and note that the document specifically states in relation to the capital expenditure program that "*financial targets beyond 2009/10 have not been included in this NMP.*"[139].

Huegin's comments in relation to the benefits and timing that the program is framed around a strategy, intent, and indicated initiatives, and noted Ergon Energy's process for selection of feeder improvement projects. Through its examination of Ergon Energy's processes Huegin observes that:

> *"… while these processes are not yet formally documented, Ergon Energy is currently undertaking, and has undertaken in the past, parts of the process.",*

133 Ergon Energy, 2009, *"Feeder Improvement Program"*, AR341, 24 March 2009.
134 Ergon Energy, *"Network Management Plan Part A, Electricity Supply for Regional Queensland 2008/09 to 2012/13"*, AR402, and Part B, AR445.
135 Ergon Energy Corporation Limited, 2010, *"Confidential Revised Regulatory Proposal to the Australian Energy Regulator, Distribution Services for 1 July 2010 to 30 June 2015"*, p. 124, 14 January 2010.
136 Ergon Energy, 2009, *"Feeder Improvement Program",* AR341, 24 March 2009.
137 ibid. p. 16.
138 ibid. p. 6.
139 Ergon Energy, *"Network Management Plan Part A, Electricity Supply for Regional Queensland 2008/09 to 2012/13",* AR402, p. 75.

Concluding that:

> *"…Huegin can confirm that the process involves estimating the benefits of all potential feeder improvements, in terms of the customer minutes saved, and providing an indication of the year within which the works will be carried out, based on priority and other factors."*[140]

Based on Huegin's review it is clear to PB that Ergon Energy does consider the benefits and timing of reliability and quality of supply capex, however it does so only in an operational context at the time of developing a specific item of expenditure.

In reviewing the worst performing feeder improvement program, PB's concern is that the benefits and timing of the capex proposed for the next regulatory control period is not demonstrated. In our review of the revised proposal, PB has not identified any new information to alter this view.

Addressing an identified need

In PB's review of the worst performing feeder program we noted that while the supporting documentation contains performance information, it does not include any detailed analysis of the causes of the poor performance of the identified worst performing feeders. PB went on to state our concern that since the causes of poor performance are not recognised, it is unclear how the proposed expenditure addresses the performance issues, and hence how the proposed cost has been determined[141].

Ergon Energy argues that it does investigate the causes of poor feeder performance and that the supporting documentation submitted with its proposal contains causal analysis of feeder performance[142]. PB concurs that the supporting documents contain causal analysis of the worst performing feeders, and notes that the wording of our review may not clearly convey the point that was being made and requires clarification.

PB's primary concern is that the analysis in the supporting documentation does not identify the causes of poor performance of the identified feeders that are to be targeted through the proposed $40.2m expenditure over the next regulatory control period. Hence, in our opinion the relationship between the need, scope, and the proposed expenditure is not demonstrated in the supporting documentation.

As the relationship between the need, scope, and the proposed level of expenditure was unclear, PB concluded that the proposed capex appeared to be a general provision for feeder improvement works rather than a program of specific targeted expenditure. In its revised proposal, Ergon Energy conditionally agrees that the forecast capex is a provision to

140 Huegin Consulting Group, 2010, *"Review of Qld Draft Determination & Parsons Brinckerhoff Report on Ergon Energy's Regulatory Proposal"*, p.55, 12 January 2010. PB notes in the revised Huegin report dated 18 January 2010 that this point has been amended. See Huegin report dated 18 January 2010, p. 60.

141 Parsons Brinckerhoff Australia Pty Limited, 2009, *"Review of Ergon Energy regulatory proposal for the period July 2010 to June 2015"*, p.60, 24 November 2009.

142 Ergon Energy Corporation Limited, 2010, *"Confidential Revised Regulatory Proposal to the Australian Energy Regulator, Distribution Services for 1 July 2010 to 30 June 2015"*, p. 124, 14 January 2010.

address feeder performance[143]. Huegin goes further confirming unconditionally that the feeder improvement program is a provision for feeder improvement works[144].

Ergon Energy argues that as reliability problems change over time, it cannot definitively scope this program ex-ante. In PB's opinion, the ex-ante scoping of such a program is difficult, however scoping such a program does not necessarily imply that each feeder to be targeted by the expenditure is definitively identified. As PB noted above, section 6 of the feeder improvement document identifies SAIDI savings of 21 minutes for improvements to 80 feeders[145]. In our view, in order to determine the level of improvement that will be achieved from the proposed expenditure, and in order to estimate a cost to achieve this level of improvement, the scope of proposed works should be more well defined than just the rectification of 42.5 unidentified feeders within the list of worst performing feeders at a unit cost of $653 k (excluding overheads).

While we acknowledge that Ergon Energy does undertake causal analysis, the issue is that the information provided by Ergon Energy does not reasonably demonstrate that the proposed investment of $653 k per feeder is the efficient investment required to address the causes of the poor feeder performance. PB notes that we have not found any new information in Ergon Energy's revised proposal that demonstrates this efficiency.

Duplicate funding

In reviewing the worst performing feeder program, PB noted that other capex and opex expenditures are proposed to address the same performance problems. Our concern being that this has not been taken into account in the proposed level of capex funding.

In its revised proposal, Ergon Energy states that it does not consider that duplication of expenditure is possible due to the operation of its planning processes, citing the Network Management Plan's requirement that maintenance and operational solutions are also considered with reliability improvement initiatives. Ergon Energy also notes that if expenditure is not found to be required on the targeted feeders due to other expenditure, then the funds can be redirected to alternative poor performing feeders[146]. Huegin notes that while the proposed expenditure is not specifically targeted, and while Ergon Energy's process relating to this expenditure is not formally documented, Ergon Energy's[147]:

> *"…proposed process is sufficient to ensure that any expenditure resulting from the FIP will not overlap with any other capital or operating expenditure initiatives."*

In PB' opinion the issue is not that funding, once approved, cannot be spent addressing a need that has already been addressed, or that funding can be redirected to expand a program or for other uses, but that the proposed level of capex funding sought by the business is demonstrated to be an efficient level of funding. In PB's view, while the

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143 ibid. pp. 124-125.

144 Huegin Consulting Group, 2010, *"Review of Qld Draft Determination & Parsons Brinckerhoff Report on Ergon Energy's Regulatory Proposal"*, p. 55, 12 January 2010. PB notes the revised Huegin report dated 18 January 2010 has been amended. See Huegin report dated 18 January 2010, p. 60

145 PB notes that this addressed both the Generic Feeder Program (not reviewed by PB) and the Worst Performing Feeder Program (reviewed by PB).

146 Ergon Energy Corporation Limited, 2010, *"Confidential Revised Regulatory Proposal to the Australian Energy Regulator, Distribution Services for 1 July 2010 to 30 June 2015"*, pp. 124-125, 14 January 2010.

147 Huegin Consulting Group, 2010, *"Review of Qld Draft Determination & Parsons Brinckerhoff Report on Ergon Energy's Regulatory Proposal"*, pp. 60-61, 12 January 2010. PB notes the revised Huegin report dated 18 January 2010 has been amended. See Huegin report dated 18 January 2010, p. 65

procedural controls offered by Ergon Energy are an essential part of prudent and efficient business management, they do not demonstrate that the proposed level of capex does not include funding that is essentially addressing the same identified need.

In reviewing of the worst performing feeder improvement program, PB's concern is that other capex and opex expenditures are proposed to address the same performance problems, and that this has not been taken into account in the proposed level of reliability and quality improvement capex funding proposed. In our review of the revised proposal, PB has not identified any new information to alter this view.

Basis of the adjustment

In its revised proposal, Ergon Energy argues that the adjustment applied to the Reliability and Quality Improvement capex does not meet the capital expenditure criteria as its prudence and efficiency has not been assessed. Ergon Energy also argues that historical expenditure was much lower than planned due to resource reallocation; the likely requirement for reliability improvement expenditure is not accounted for in the method applied; and the adjustment method does not consider Ergon Energy's circumstances[148].

In our previous review of Ergon Energy's reliability and quality improvement capex proposal, PB concluded that Ergon Energy had not reasonably demonstrated that their capex proposal was prudent or efficient. Consequently, PB sought to identify a benchmark level of reliability and quality improvement capex that represented a prudent and efficient level of expenditure. In PB's view, as the QCA had reviewed and approved Ergon Energy's capex for the current period, it is likely that it represents a reasonably prudent and efficient level of expenditure.

Additionally, as noted in our previous review, while we did not review the prudence and efficiency of Ergon Energy's historical reliability and quality improvement capex, our review also did not reveal any reason or factors to indicate that reliability and quality improvement capex forecasts should significantly differ from current period expenditure (excluding the SCADA acceleration capex) [149]. We also note that Ergon Energy is seeking a real increase of 131% in the next regulatory period, and in our opinion, factors that would drive such a significant increase should be readily apparent in the business documentation, and in our view they are not.

Moreover, by using Ergon Energy's historical capex as a benchmark level of expenditure, PB is of the view that this approach accounts for the current circumstances of the business, and as noted above, with no significant changes to the circumstances of the business apparent from the business documentation, also accounts for the foreseeable circumstances of the business. This issue is discussed further below in relation to the MSS targets.

PB notes that Ergon Energy argues that expenditure in the current period was *"much lower than planned due to a reallocation of resources to meet regulatory obligations to connect customers"* [150], and that the approach does not consider the reduction of Minimum Service Standard (MSS) targets.

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148 Ergon Energy Corporation Limited, 2010, *"Confidential Revised Regulatory Proposal to the Australian Energy Regulator, Distribution Services for 1 July 2010 to 30 June 2015"*, pp. 125-126, 14 January 2010.

149 PB, *"Review of Ergon Energy regulatory proposal for the period July 2010 to June 2015"*, p. 61, 24 November 2009.

150 Ergon Energy Corporation Limited, 2010, *"Confidential Revised Regulatory Proposal to the Australian Energy Regulator, Distribution Services for 1 July 2010 to 30 June 2015"*, p. 125, 14 January 2010.

While, Ergon Energy argues that historical expenditure was lower than planned, the impact of this is not apparent in the October 09 reliability performance report, which states that the SAIFI trend in historical reliability performance is consistently improving despite the adverse impact of the suspension of Live Line work and restrictions imposed on operating ABS[151]. This report also notes that SAIDI has not improved proportionally with SAIFI and appropriately notes that focus now needs to be placed on outage duration[152], that is, on outage response. PB notes that the analysis presented in the reliability performance report is depicted in a number of graphs showing SAIDI and SAIFI trends against MSS[153] and STPIS[154] targets. In our view these graphs, while showing some volatility year on year, present a consistently improving reliability trend which is also consistent with the respective targets. In PB's opinion, the trends identified in the reliability performance report show that consistent improvement according with the performance targets is being achieved under the historical expenditure levels.

PB notes that the MSS targets do reduce over the next regulatory control period. However we note that at the time the Feeder Improvement Program documentation was prepared, the anticipated reduction in the MSS targets were more significant than the targets set on 24 April 2009. Ergon Energy's October 09 reliability performance report notes that the *"… performance improvement required over the next regulatory period to meet the 2014/15 targets is now further relaxed …"*[155]. For example, as can be seen from Table 2.13 and Table 2.14, the relaxation of the MSS targets amounts to a change from a 4 minute per annum decrease in urban SAIDI to a 1 minute per annum decrease. Similarly the relaxation of the MSS target for urban SAIFI changes from a 0.09 decrease to a 0.02 decrease in 2012-13 over the 2011-12 target.

Table 2.13 SAIDI Minimum Service Standards comparison

		2010-11	2011-12	2012-13	2013-14	2014-15
Pre 24 April 2009 MSS targets	Urban	146	142	138	-	-
	Short Urban	419	409	399	-	-
	Long Rural	956	932	909	-	-
Post 24 April 2009 MSS targets	Urban	149	148	147	146	145
	Short Urban	424	418	412	406	400
	Long Rural	964	948	932	916	900

Source: PB analysis.

Table 2.14 SAIFI Minimum Service Standards comparisons

		2010-11	2011-12	2012-13	2013-14	2014-15
Pre 24 April 2009	Urban	1.97	1.94	1.85	-	-
	Short Urban	3.94	3.88	3.70	-	-
	Long Rural	7.39	7.28	6.95	-	-
Post 24 April 2009	Urban	1.98	1.96	1.94	1.92	1.90
	Short Urban	3.95	3.90	3.85	3.80	3.75
	Long Rural	7.40	7.30	7.20	7.10	7.00

Source: PB analysis.

151 Ergon Energy, 2009, *"Annual Network Reliability Performance Report 2008/2009"*, RP906c, pp. 4-5, 30 October 2009.
152 ibid.
153 ibid.
154 ibid, p. 17.
155 ibid, p. 13.

In PB's opinion, under historical expenditure levels Ergon Energy has been achieving a consistent reliability improvement trend which accords with the MSS targets prior to the 24 April 2009. Moreover, while the overall trend in the MSS targets is tightening, the relaxation in these targets post the development of the Feeder Improvement Program has not been inconsiderable. Hence PB is not of the view that the historical under spend or the reduction in the MSS targets has a significant bearing on the use of historical expenditure as a prudent and efficient benchmark.

Nonetheless, PB has reviewed the basis of our calculations of the historical level of expenditure, and notes an average historical under spend of $1.9m which was not accounted for in our original calculations. Allowance for this has now been incorporated into PB's recommended adjustment.

Conclusion

In our previous review of Ergon Energy's reliability and quality improvement capex proposal, PB found that it could not conclude that the capex proposal is prudent and efficient. In PB's view, the capex proposed for the worst performing feeder program represents a provision for the improvement of feeders, and that there is no demonstrated basis for targeting 42.5 feeders (as opposed to any other number), nor has a rationale for the unit cost of $653 k per feeder been demonstrated. In addition, we are concerned that the proposed funding may duplicate other funding areas, and Ergon Energy has not provided any new information to demonstrate that duplication has not occurred in the proposed funding. PB is also of the opinion that Ergon Energy's revised proposal does not provide any new information which identifies any drivers or factors which would reasonably account for the proposed increase in reliability and quality improvement capex.

PB has reviewed Ergon Energy's revised proposal, and in reviewing the new material we have concluded that Ergon Energy has not demonstrated the prudency and efficiency of its revised reliability and quality improvement capex proposal. However, in reviewing our previous calculations we have noted an average historical under spend of $1.9m per annum, and have incorporated this into our recommended adjustments. PB recommends that the AER apply the adjustments shown in Table 2.15 to Ergon Energy's revised proposal.

Table 2.15 Recommended capex for reliability and quality improvement

Expenditure category	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy revised proposed	18.5	21.5	25.2	29.0	30.8	125.0
PB adjustment	(0.7)	(2.7)	(5.4)	(8.1)	(9.6)	(26.5)
PB recommendation	17.8	18.8	19.8	20.9	21.2	98.5

Source: PB analysis.

2.5 CPI and capex cost escalation process

PB is required to review Ergon Energy's use of CPI to establish real and nominal escalators in its capex modelling and inflate and deflate expenditures over the next regulatory control period, taking into account the revised proposal and responses to follow-up questions by the AER.

In its original proposal, Ergon Energy modelled calculations to apply CPI and real cost escalators to its forecast capex allowance to present it in 2009-10 real values. The process involved the inflation of 2007-08 real values up to nominal values across the next regulatory control period and subsequent deflation of these nominal values to arrive at 2009-10 real values, as required by the AER. In its review of Ergon Energy's original proposal, PB noted that the set of CPI values used by Ergon to inflate 2007–08 real values to nominal values was different from the set used to deflate the nominal values back to the final 2009–10 real values. For the avoidance of doubt, the CPI values are presented in Table 2.16. PB recommended that the same set of CPI values be used to inflate as to deflate and that the values to be used should be Ergon Energy's forecast of CPI.

Table 2.16 CPI sets used in Ergon Energy's capex modelling

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Ergon Energy's forecast CPI – used for inflation	1.75%	2.75%	2.45%	2.45%	2.45%	2.45%	2.45%
CPI as per PTRM – used for deflation	1.75%	2.75%	2.00%	2.50%	2.50%	2.50%	2.50%

Source: Ergon Energy spreadsheet "SC Opex and Capex Model.xls".

PB notes the singular impact of incorporating the same CPI to inflate and deflate the expenditure in the original model resulted in a reduction in the forecast allowance of some $20.4m.

2.5.1 Revised proposal and new information

In its revised proposal, Ergon Energy maintains that the use of the two different sets of CPI values is correct. To clarify Ergon Energy's intents, the AER posed two further questions to it regarding this matter[156]. In its responses to these questions, Ergon Energy indicated that its rationale was to align the CPI values used in deflating nominal values to 2009-10 real values with the CPI values used in the AER Post Tax Revenue Model such that these same nominal values would be maintained in both the PTRM and the capex forecast.

2.5.2 PB findings and recommendation

PB understands that the calculation of forecast capex is essentially separate from the calculations undertaken in the PTRM and that there is no requirement to align the CPI values between the two calculations. PB recommends that in order to correctly calculate Ergon Energy's required capex in 2009-10 real values, it uses its forecast CPI values consistently to inflate and deflate. Furthermore, PB notes that in order to avoid the two separate stages of inflation and deflation, it would be possible to inflate Ergon Energy's 2007-08 real values directly to 2009-10 real values using Ergon Energy's forecast CPI values.

156 AER.ERG.RRP.05 and AER.ERG.RRP.18

3. Forecast non-system capex

In this section, PB reviews the following matters in relation to ENERGEX's revised forecast non-system capex proposal:

- ICT capex initiatives – justification
- ICT capex initiatives – change program
- Property – justification.

3.1 ICT capex initiatives – justification

PB is required to review in detail, and provide advice on the prudence and efficiency of the resubmitted ICT capability projects proposed as part of Ergon Energy's ICT shared costs in section 10.4.8 of Ergon Energy's revised.

In its draft decision, the AER reduced the amount of Ergon Energy's non-system ICT expenditure by approximately $47.1m (or approximately 17.6% of ICT expenditure capitalised within SPARQ), which corresponded to a proportional reduction in ICT overhead expenditure equivalent to approximately $20.4m (or approximately 4.7% of total ICT overheads).[157] This outcome resulted from PB's review of Ergon Energy's new capability initiatives associated with its proposed ICT program having regard to a range of considerations including project need and efficiency, options analysis and delivery strategy.

In particular, it was found that with the exception of its data centre reconfiguration project, Ergon Energy's proposed new capability initiatives were not supported by analysis that demonstrated prudency or efficiency.[158]

3.1.1 Revised proposal and new information

Ergon Energy has acknowledged that the business cases used to justify its non-system ICT expenditure were not advanced at the time of submitting its original proposal. However, it contends that its expenditure should not have been reduced in the AER draft decision and resubmits new information in the form of business cases to support this position.[159]

The new business cases, and accompanying documentation, account for the following new capability initiatives: (i) distribution management system; (ii) field force automation (FFA); and (iii) new ICT infrastructure.[160] These new capability initiatives directly correspond to those projects found not to be prudent and efficient in PB's initial review as there was little or no evidence quantifying the net benefits of these projects.[161]

PB notes that the new business cases supplied appear to be compiled after PB's review. In certain circumstances, it is noted that business cases require further investigation and confirmation prior to committing Ergon Energy to the expenditure (e.g. FFA project). This

157 PB Review of Ergon Energy regulatory proposal for the period July 2010 to June 2015 (pp. 19-20)
158 ibid (pp. 75-81)
159 Ergon Energy Revised Regulatory Proposal 2010-15, (p. 133)
160 ibid, *Appendix 4.2*
161 PB Review of Ergon Energy regulatory proposal for the period July 2010 to June 2015 (pp. 77-79)

suggests that the business cases are indicative at this stage, and have been prepared to address the AER's concerns in response to its draft decision.

3.1.2 PB findings and recommendation

DMS Foundation

The DMS business case outlines the scope, financial cost-benefits, risks, and dependencies of the project.[162] It identifies three main options: the option of 'do nothing', 'deferral' or the option which is based on the preferred and proposed DMS scope. It also considers a range of other non-financial benefits associated with implementing the project such as reduced risk in operating assets and increased business effectiveness.

A spreadsheet computing the financial net benefit of the DMS option was provided to justify the prudency and efficiency of the expenditure.[163] The cost components taken into account included capex, opex and service level variations, resulting in an NPV of cost equivalent to $23.8m. In contrast, the benefits that were quantified in the assessment included potential staff avoided costs in the operational control centre (OCC), as well as reliability avoided penalties/gained (i.e. SAIDI and CAIDI savings). It estimates that the implementation of the DMS option, over a 2009-10 to 2021-22 analysis period, provides a staff NPV saving of approximately $32.6m (2009-10 dollars), and a reliability NPV saving of $15.3m (2009-10 dollars). Taken together, the overall NPV of implementing the DMS option is estimated to be $24.2m (2009-10 dollars).[164]

In conducting its assessment of the new information provided by Ergon Energy, PB undertook a sensitivity analysis of the benefits driving the NPV results. Specifically, the avoided costs associated with OCC from the implementation of the DMS project are driven by growth rates for control room work volume and complexity over a 12 year evaluation period. PB reduced the base-level growth rate from 3% to 1%, thereby reducing the staff avoided costs associated with implementing the project. All else being equal, the reduction in the growth rate still resulted in a positive NPV of $0.8m.

Overall, PB is satisfied with the overall investment proposition of the project, including the need to deliver real-time network solutions that will enable Ergon Energy to better provide decision and response capabilities in outage and reliability management. Together with the expected avoided costs to be realised from the project, PB recommends approval of the expenditure.

Field Force Automation (FFA)

PB has reviewed the new documentation provided by Ergon Energy to justify its FFA project including the provision of a position paper, a business case that briefly outlines the objectives, scope and financial cost-benefit analysis of the project, as well as high level benefits summary outlining customers operations and maintenance activity savings arising from the implementation of the project.[165]

162 Ergon Energy 21 December 2009, RP904c_EE_DMS_Business Case High Level_21Dec09 and RP903c_EE_DMS_Business Case Gate 1 Summary_21Dec09

163 Ergon Energy 21 December 2009, RP902c_EE_DMS_Business Case Spreadsheet_21Dec09

164 Ergon Energy 21 December 2009, RP902c_EE_DMS_Business Case Spreadsheet_21Dec09, *Summary of costs and benefits worksheet*

165 Ergon Energy 16 December 2009, RP964c_FFA Business Case AER response V0.1_16Dec09; RP965c_FFA Position Paper AER response v0.4_16Dec09; RP963c_Appendix 1 Benefits Summary AER response V0.1

The business case, and supporting material used to justify the expenditure, specifies that the project expenditure is expected to take place over a 7 year period ($60.8m), with an initial project cost of $34.7m. This differs to the $19.1m submitted in its regulatory proposal, as Ergon Energy has expressed that it intends to cost recover any additional costs (initial or ongoing) from the expected project benefits achieved during the regulatory period.[166] On this basis, the analysis suggests that the project is expected to generate an NPV of approximately $19.61m. [redacted]

In conducting its review, PB undertook a sensitivity analysis of total labour savings to ascertain the viability of the project. Specifically, the projected benefits were reduced by as much as 30% from [redacted]. This resulted in an NPV of [redacted], suggesting that a notable reduction in benefits would still make the Project commercially viable all else being equal.

Overall, PB is satisfied with the need and net benefits of the project and recommends approval of the expenditure.

New ICT infrastructure

The new ICT infrastructure business case provided by Ergon Energy seeks an amount of $1m per annum over the next regulatory control period[169] to take advantage of "emerging technologies that currently do not exist or are immature".[170] For the purposes of demonstration, two projects are appraised in the business case including (i) unified communications and (ii) identity and access management (IAM). However, it is implied that these projects are illustrative in nature only, as "it is not yet clear which emerging technologies will be analysed in the later years of the regulatory control period".[171]

The unified communications and IAM projects appraised are forecast to cost $3m over a three year period. An NPV of $1.7m and $1.1m respectively are estimated once direct benefits and indirect benefits of these projects are taken into account.

Despite these findings, it is PB's view that the business case for this expenditure is neither focussed or project specific. That is, the justification for an improvement in strategic technology appears generic, despite the use of two examples that demonstrate a positive net return on investment. Specifically, justification for expenditure should be project specific and considered on a case-by-case basis to ensure that funds are located to their most efficient uses. As such, PB does not recommend approval of this project.

PB recommendation

PB has reviewed the new ICT capex information provided by Ergon Energy in response to the AER's draft decision. As discussed above, Ergon Energy and SPARQ have produced new business case documents for the three new capability projects that were found not to be

166 Ergon Energy Revised Regulatory Proposal 2010-15, (p. 134)
167 Ergon Energy 16 December 2009, RP964c_FFA Business Case AER response V0.1_16Dec09, *CostBenefit Worksheet*
168 Ergon Energy 16 December 2009, RP963c_Appendix 1 Benefits Summary AER response V0.1
169 Ergon Energy Revised Regulatory Proposal 2010-15, (p. 135)
170 Ergon Energy 21 December 2009, RP901c_EE_New Strategic ICT_Business Case_21Dec09, (p. 2)
171 Ibid.

prudent and efficient in PB's original review. Of the three business cases reviewed (DMS, FFA and new ICT infrastructure), PB is satisfied with the need and reasonableness of the DMS and FFA initiatives, provided the net financial benefits estimated for these projects are realised. However, PB is not satisfied with the proposed expenditure for new ICT infrastructure as it does not address a specific project need, but rather uses two projects as examples to demonstrate the potential benefits of such new ICT infrastructure initiatives.

Overall, PB recommends a business-as-usual ICT expenditure forecast, plus the new capability projects data centre reconfiguration, DMS and FFA. Table 3.1 sets out PB's revised 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.

Table 3.1 Recommended ICT expenditure for SPARQ capex

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
SPARQ revised proposal	67.2	64.1	52.5	47.9	35.2	266.9
PB adjustment	(0.9)	(1.2)	(1.0)	(1.0)	(1.0)	(5.1)
PB recommendation	66.4	62.8	51.5	46.9	34.1	261.7
Change %	(1.3)	(1.9)	(2.0)	(2.1)	(2.9)	(1.9)

Note: Figures may not sum precisely due to rounding

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 baseline costs and assumed the increase in the ICT overhead during the next regulatory control period is predominantly 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 3.2.

Table 3.2 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
Assumed baseline	61.0	61.0	61.0	61.0	61.0	305.2
Increase in ICT ($m)	9.8	21.6	31.7	34.7	31.6	129.4
% reduction in SPARQ capex (see table 3.1)	(1.3)	(1.9)	(2.0)	(2.1)	(2.9)	(1.9)
Proportional reduction in ICT overhead	(0.1)	(0.4)	(0.6)	(0.7)	(0.9)	(2.8)
PB recommended ICT overhead	70.8	82.2	92.1	95.0	91.8	431.8

Source: PB analysis.

PB recommends a reduction of $2.8m for Ergon Energy as shown in Table 3.3 due to the reduced ICT service charge. Based on the Ergon Energy's approved cost allocation method, 77% of overheads have been allocated to capex and 23% have been allocated to opex.[172]

172 PB, Review of Ergon Energy regulatory proposal for the period July 2010 to June 2015, 2009, p. 17

Consequently, PB's advice reflects into adjustments of approximately $2.16m for capex and $0.64m for opex.

Table 3.3 Recommended overheads for Ergon Energy

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
AER draft decision	379.3	389.2	381.4	379.6	376.8	1,906.3
Ergon Energy revised proposed	381.0	395.4	384.8	383.7	381.8	1,926.7
PB adjustment	(0.1)	(0.4)	(0.6)	(0.7)	(0.9)	(2.8)
PB recommendation	380.9	395.0	384.2	383.0	380.9	1,923.9

Source: PB analysis.

3.2 ICT capex initiatives – change program

PB is required to review in detail, and provide advice on the prudence and efficiency of the revised change program expenditures as part of Ergon Energy's non-system ICT capex, outlined in section 10.4.6 of Ergon Energy's revised proposal.

During the initial review process, PB found that Ergon Energy's ICT expenditure for the next regulatory control period did not reconcile with the bottom-up build up of its ICT forecast as submitted in the RIN. In response to a request for clarification, it was found that an amount of $50m for a 'Change Program' was included in the $92.9m ICT expenditure submitted for review (or approximately 54% of total ICT expenditure capitalised within Ergon Energy). Table 3.4 presents the reconciliation provided to PB by Ergon Energy.

Table 3.4 Ergon Energy ICT capex reconciliation – bottom-up versus proposed

Asset class	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ICT expenditure	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)
Subtotal indirect costs	4.8	4.5	4.4	4.2	4	21.9
ICT expenditure as submitted in the RIN	20.3	18.9	18.2	17.1	18.4	92.9

Source: Ergon Energy, PL840c_EE_ICT_Expenditure Reconciliation_1Sep09.xls.

However, as no information was provided to demonstrate the underlying prudency and efficiency of the 'Change Program', it was recommended that the additional expenditure above and beyond ICT projects not be approved. As a result, the AER reduced the total ICT expenditure by $65m to reflect expenditure that excluded costs associated with the change program.[173] The $65m was determined on the basis of calculating the direct and indirect proportion of expenditure related to ICT projects only, taking into account overhead,

173 AER Draft Determination (p. 106)

escalation and conversion factors. This resulted in an approved ICT expenditure of $27.7m for the next regulatory control period[174].

3.2.1 Revised proposal and new information

In its revised proposal, Ergon Energy confirms that the $10m per annum requested for the change program is not directly related to ICT projects, but rather composed of non-ICT projects associated with transforming ICT projects and organisational change. In particular, Ergon Energy has revised its original proposal of $10m per annum to $2m per annum. The revised amount is based on historical incremental spend of non-ICT change projects, which averaged around $1.3m per year in 2008-09 and 2009-10, and $2.25m in 2007-08. On this basis, it is submitted that the benchmark expenditure required for the level of transformation needed over the next regulatory control period is expected to be approximately $2m per annum.[175]

To supplement its review, PB requested further information from Ergon Energy to ascertain the underlying prudency and efficiency of the expenditure. In particular, greater detail outlining Ergon Energy's historical expenditure for this program, along with business cases justifying the on-going need for the program was sought.[176] In response to this request, Ergon Energy has advised that historical spends are impossible to identify accurately as there have been a number of approaches in the way Change Programs have been managed and funded in the past[177]. Further, it noted that business cases for Change Programs in the 2010-15 regulatory control period would be developed as required for internal approval. Two business cases, however, were submitted to illustrate examples of projects in the change program from previous years including the (i) whole of commission project that seeks to create a best practice assessment management commissioning process; and (ii) field mobile computing (FMC) carryover project.[178]

3.2.2 PB findings and recommendation

A review of the two business cases submitted from previous years indicates that the total requested funds were equivalent to approximately $1.9m (i.e. $0.333 for whole of commissioning project and $1.563 for FMC carryover project).[179] Although this suggests that the $2m per annum amount being submitted for review over the next regulatory control period falls within a reasonable range, PB does not believe that the provision of selected historical business cases is sufficient to justify the expenditure for the next regulatory control period. Specifically, Ergon Energy was unable to provide detailed information at a project or program level justifying the $2m per annum expenditure for the forecast period. Therefore, it appears that the total amount of $10m over the 5-year period submitted for review by Ergon Energy represents an anticipated pool of funds that may or may not be needed . For this reason, PB does not recommend approval of the expenditure.

174 PB, Review of Ergon Energy regulatory proposal for the period July 2010 to June 2015, 2009, p. 81
175 Ergon Energy Revised Regulatory Proposal 2010-15, (pp. 128-129)
176 Ergon Energy 17 February 2010, Email response to PB.ERG.RRP.04 (confidential)
177 Ibid.
178 Ergon Energy 17 February 2010, Email response to PB.ERG.RRP.04 (confidential), *Whole of Commissioning Business Case – PRP995c and FMC11 Carryover Project Business Case*
179 PB notes that whole of commissioning process business cases estimated a negative NPV of $0.959m, whilst the FMC business case estimated a positive NPV of $2.591m. In both cases, little or no discussion of these financial results was made within the business case, including a clear discussion on the assumptions used to monetise the benefits associated with implementing the projects.

PB considers that no new information has been provided to justify the underlying prudency and efficiency of the change program associated with ICT for the next regulatory control period. For this reason, PB recommends that the findings of its initial review be retained. Table 3.6 sets out PB's recommendation for Ergon Energy's ICT expenditure for the next regulatory control period.

Table 3.5 Recommended ICT expenditure for Ergon Energy capex

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
AER draft decision	7.2	5.8	5.1	4.0	5.6	27.7
Ergon Energy revised proposed	10.0	8.9	8.4	7.6	8.6	43.5
PB adjustment	(2.8)	(3.1)	(3.3)	(3.6)	(3.0)	(15.8)
PB recommendation	7.2	5.8	5.1	4.0	5.6	27.7

Source: PB analysis.

3.3 Property - justification

PB is required to review in detail, and provide advice on the prudence and efficiency of the resubmitted major property projects proposed in section 10.4.7 of Ergon Energy's revised proposal.

In PB's original review of Ergon Energy's land and building capex proposal, a number of issues regarding the prudency and efficiency of the proposal were identified. A summary of these issues is outlined below:

- the Corporate Property Strategy had not been updated since 2006 to account for changes that had occurred in the interim period
- a lack of data provided to support prioritisation of property projects
- business cases had not been developed for major property projects
- alternative project options had not been developed for major property projects
- concern regarding Ergon Energy's ability to deliver the property strategy in the first two years of the next regulatory control period.

PB found that these issues were material, and concluded that Ergon Energy had not demonstrated that the proposed capex was prudent and efficient. Consequently PB recommended that the major projects be removed from the regulatory proposal, and that the proposed land and buildings capex be reduced from $386.4m to $196.0m, a reduction of $190.8m or 49% of the proposed expenditure. This recommendation was in line with business-as-usual costs.

In its draft decision, the AER considered PB's advice and found that the major property project expenditures proposed by Ergon Energy were not supported by business case documentation, were not demonstrated to be prudent and efficient, and should be removed from the capex proposal. The AER requested that Ergon Energy model the impact of the

AER's draft decision on property capex and Ergon Energy advised that the adjustment to forecast property capex was a reduction of $188m[180].

3.3.1 Revised proposal and new information

Ergon Energy's revised proposal is for a corporate property capex allowance of $263.8m (real $07-08)[181]. This is a $3.0m reduction from Ergon Energy's original proposal of $266.8m (real $07-08)[182].

The escalated value of the total property program in Ergon Energy's original proposal was $386.8m[183]. Ergon Energy's revised property proposal is for $388.2m[184].

Ergon Energy's revised proposal includes a number of changes in relation to non-system property capital expenditure, as outlined in Table 3.6.

Table 3.6 Changes to Ergon Energy's original proposal

Expenditure category	Change in capex ($2007-08 m)	Reason
Cairns – Swallow Rd	$7.1m	Amended scope
Rockhampton – Stage 1 Glenmore Rd	$4.8m	Completion of pre-existing commitment
Rockhampton – Stage 2 Glenmore Rd	$2.8m	Amended scope
Mackay – Ness St	$15.9m	Completion of pre-existing commitments
Maryborough – Searle St	$8.8m	Amended scope
Data Centre	$8.8m	Removed from submission
Townsville – Ingham Rd	($20.0m)	Refined estimate of works
Toowoomba – South St	($3.3m)	Reprioritised
Hervey Bay	($11.0m)	Completion of pre-existing commitments
Purchase of Land	($5.3m)	Removed from submission
Total expenditure variance	($3m)	

Source: PB analysis

These non-system property capex revisions aggregate to a $3.0m ($07-08) reduction from Ergon Energy's original proposal.

Ergon Energy provided significant new information relating to property capex in its revised proposal. The relevant new information is summarised below.

180 AER, 25 November 2009, Ergon Energy Draft Distribution Determination 2010-11 to 2014-15, p.118
181 Ergon Energy, Non-Network Response to Draft AER Determination, 17 December 2009, p. 5
182 Ibid, p.5
183 Ergon Energy, Regulatory Proposal to the AER, Distribution Services for period 1 July 2010 to 30 June 2015, p.228 & p.234.
184 Ergon Energy, Revised RIN proposal for the period 1 July 2010 to 30 June 2015, as advised by the AER.

Corporate Property Strategy

Ergon Energy provided new information and supporting documentation regarding the status of the Corporate Property Strategy[185]. This included explanations regarding the development of work scopes and cost estimates between the approval of the Corporate Property Strategy in 2006 and Ergon Energy's revised proposal in 2010; independent site condition assessment reports; and business cases for each major property project.

Deliverability

Ergon Energy's revised proposal includes new information regarding delivery of the overall property plan and implementation considerations for each major project. Ergon Energy states that the delivery program for the refined major works is scheduled to reflect realistic and reasonable time allowances for documentation, tendering, procurement, approvals, construction and commissioning[186]. Implementation considerations are also provided in the business cases, which outline the affordability, implementation risks (achievability) and implementation strategy for each major property project[187].

Major project prioritisation

Ergon Energy's revised proposal provides new information regarding the prioritisation of major projects[188]. This includes explanations regarding the method in which the overall works program is sequenced and the provision of business cases from which the relative prioritisation of proposed works was reviewed and ordered[189].

Business case development and alternative project options

Ergon Energy's revised proposal includes business cases for all major non-system property projects[190]. The business cases provide site options analysis for each major property project. The site options analysis involves comparison of two alternatives for each major project, namely a business-as-usual option, and the development of a new facility or upgrade to an existing facility. These are compared using financial and non-financial criteria derived from Ergon Energy's Key Result Area's (KRAs)[191], as outlined below.

Financial KRA:

- commercial performance

Non-financial KRA's:

- operational excellence
- risk and compliance
- people
- sustainability and climate change

185 Ergon Energy, Non-Network Response to Draft AER Determination, 17 December 2009, p. 3.
186 Ergon Energy, Non-Network Property Response to AER Draft Determination, 17 December 2009, p. 4.
187 Ergon Energy, Hervey Bay Business Case, 16 December 2009, p. 10.
188 Ergon Energy, Non-Network Property Response to AER Draft Determination, 17 December 2009, p. 4.
189 Ibid, p. 4
190 Ibid, p. 3.
191 Ergon Energy, Mackay Business Case, 16 December 2009, p. 8.

- customers and community.

3.3.2 PB findings and recommendation

This section outlines PB's advice to the AER based on the new information provided by Ergon Energy in relation to property expenditure for the next regulatory control period.

Corporate Property Strategy

PB has reviewed the new information and supporting documentation provided in Ergon Energy's revised proposal in relation to the Corporate Property Strategy[192]. This includes explanation regarding project changes that can and have occurred over time due to refined work scopes, cost estimates, asset market values and implementation prioritisation[193]. PB notes that Ergon Energy has updated its proposal with new information regarding work scopes and cost estimates based on newly commissioned independent site assessment reports and business cases[194]. This ongoing revision approach explains the variation in major project scopes and costs that have occurred between the development of the Corporate Property Strategy in 2006 and Ergon Energy's revised proposal in 2010.

As a result of the new information provided in the revised proposal, PB is satisfied that Ergon Energy's Corporate Property Strategy is up to date and relevant as an over aching planning framework for corporate property in the next regulatory control period.

Deliverability

PB has reviewed the new information provided in relation to deliverability of the property program in the next regulatory control period. PB notes that Ergon Energy's revised proposal involves the deferred implementation of the largest capex project, Townsville, from 2010-11 to 2012-13[195], and the removal of the Data Centre building which was also forecast for implementation in the first half of the 2010-15 regulatory control period. These adjustments reduce the magnitude of the program over the first two years and assist in smoothing the schedule of major property works across the next regulatory control period.

These changes, combined with the fact that Ergon Energy has already awarded the first of the construction contracts[196], demonstrate, in PB's opinion, that delivery of the property program according to the proposed schedule is reasonable and achievable.

Major project prioritisation

PB reviewed the new information relating to the prioritisation and timing of major property projects. PB notes that the relative prioritisation of projects was reviewed following completion of the business cases prepared for each major project in December 2009[197] and that this review resulted in adjustments to the proposed timing of major projects, such as the deferment of the Townsville project from 2010-11 to 2012-13[198]. In PB's opinion, this re-prioritisation demonstrates that the proposed timing for implementation of major projects

192 Ergon Energy, Non-Network Property Response to the AER Draft Determination, pp. 3-4.
193 Ibid, p. 3-4.
194 Ibid, p. 4
195 Ergon Energy, Townsville Business Case, 16 December 2009, p. 14.
196 Ergon Energy, Non-Network Response to AER Determination, 17 December 2009, p. 5.
197 Ibid, p. 4
198 Ergon Energy, Townsville Business Case, 16 December 2009

is up to date from a prudency point of view. The efficiency of this major project expenditure is discussed in the business case development section below.

Business case development and alternative project options

PB notes that business cases were provided for all major projects in Ergon Energy's revised proposal, and that these documents include the assessment of alternative project options. PB has reviewed the scenario options assessment presented in the business case document for each site, and notes the following in relation to Ergon Energy's scenario options assessments:

- a scoring methodology has been applied to evaluate both financial and non-financial aspects of each option
- no sensitivity analysis was apparent in the documentation to consider the sensitivity of the recommended option to the scoring system weighting
- the cumulative weighting of financial to non-financial criteria is 40% to 60%, respectively
- comparison of financial (NPV) results alone, indicates that 'business-as-usual' (i.e. scenario 1) is the preferred option for all major projects, with the exception of Mackay
- the comparative options assessments indicate a preference to develop new facilities or upgrade existing facilities (i.e. scenario 2) in all cases
- the 'dollars ($m) per weighted KRA index point' used in the scoring system differs greatly between business cases, and indicates that the cost of generating a weighted KRA index point is highest (least cost efficient) for Townsville and Rockhampton.

In PB's opinion, the use of a scoring methodology is in principle a sound approach. However without appropriate development, calibration, and careful application, these methods can be unreasonably biased, lack consistency in application, and can be difficult to interpret.

Table 3.7 presents Ergon Energy's analysis of the financial aspects of each business case.

Table 3.7 Comparison of financial scores and NPV analysis between scenario options for each major property project.

Major property project	Financial Performance (weighted KRA score)		Preferred option	NPV analysis ($m)		Preferred option
	BAU	Scenario 2		BAU	Scenario 2	
Townsville	1.88	0.66	BAU	-0.23	-12.40	BAU
Cairns	1.46	1.15	BAU	3.98	2.21	BAU
Hervey Bay	1.86	0.74	BAU	1.44	-3.24	BAU
Maryborough	1.84	1.12	BAU	-1.49	-8.18	BAU
Rockhampton	1.92	0.87	BAU	-1.20	-17.70	BAU
Mackay	0.55	1.41	Scenario 2	-13.63	-5.50	Scenario 2

Source: PB analysis.

PB compared, for each major project, the financial weighted KRA index scores (commercial performance) across scenario options, and non-financial weighted KRA index scores (aggregate of operational excellence, risk and compliance, people, sustainability and climate change, and customers and community) across scenario options. This is presented in Table 3.8. This table indicates that, in terms of financial performance, BAU is the preferred option for all sites with the exception of Mackay and that for non-financial performance, the option to develop a new site or upgrade an existing facility (Scenario 2) is preferred.

Table 3.8 Comparison of financial and non-financial scores between scenario options for each major property project.

Major property project	Financial Performance (weighted KRA score)		Preferred option	Non-financial performance (weighted KRA score)		Preferred option
	BAU	Scenario 2		BAU	Scenario 2	
Townsville	1.88	0.66	BAU	1.07	2.78	Scenario 2
Cairns	1.46	1.15	BAU	1.19	2.78	Scenario 2
Hervey Bay	1.86	0.74	BAU	1.06	2.87	Scenario 2
Maryborough	1.84	1.12	BAU	1.19	2.82	Scenario 2
Rockhampton	1.92	0.87	BAU	1.15	2.74	Scenario 2
Mackay	0.55	1.41	Scenario 2	0.98	2.82	Scenario 2

Source: PB analysis.

PB analysed the weighting applied to financial (40%) and non-financial (60%) criteria within the business cases. Due to the importance of financial benefit-cost outcomes in an investment proposal setting and hence within the regulatory review process, PB was interested to determine the sensitivity to incorporating an even weighted split between financial and non-financial criteria. To conduct this simple sensitivity analysis test, PB applied a 50%-50% weighting to the weighted KRA Index between the financial and non-financial KRA's to determine the effect, if any, on the preferred options. The output of this analysis, presented in Table 3.9, has been calculated by multiplying the Weighted KRA Index for commercial performance by 1.5 to generate comparable weighted values to the cumulative weighted values for all non-financial KRA criteria.

Table 3.9 Analysis of the preferred option varying the weighting between financial and non-financial assessment criteria

Major property project	Ergon Business Cases (40% to 60%)		Preferred option (40% to 60%)	PB Analysis (50% to 50%)		Preferred option (50% to 50%)
	BAU	Scenario 2		BAU	Scenario 2	
Townsville	2.95	3.44	Scenario 2	3.89	3.77	BAU
Cairns	2.65	3.93	Scenario 2	3.38	4.51	Scenario 2
Hervey Bay	2.92	3.61	Scenario 2	3.85	3.98	Scenario 2
Maryborough	3.03	3.94	Scenario 2	3.95	4.41	Scenario 2
Rockhampton	3.07	3.61	Scenario 2	4.03	4.05	Scenario 2
Mackay	1.53	4.23	Scenario 2	1.81	4.94	Scenario 2

Source: PB analysis.

The re-weighting of the options assessment criteria to a 50%-50% split, presented in Table 3.9, indicates that the implementation of the option to develop new facilities or upgrade existing facilities (Scenario 2) remains the preferred option over business-as-usual approaches for all major projects, with the exception of Townsville and that the preference of scenario 2 for Rockhampton is only marginal. The re-weighting results in a preference for the business-as-usual approach (a score of 3.89 versus 3.77) for the major project at Townsville. It is noted however that the preference is only marginal. PB concludes that the analysis outcomes are not systemically sensitive to the relative weighting assigned to non-financial criteria, but that at a project level decisions could be altered.

The analysis above compares scenario options from a financial point of view within business case. In order to compare the financial efficiency between business cases, PB calculated a ‘dollars ($m) per weighted KRA index point’ for each major project, to enable comparison of financial (NPV) outcomes relative to non-financial outcomes across business cases. PB calculated the dollars per weighted KRA index point by taking the difference between the scenario NPV values and dividing it by the difference between the cumulative non-financial scenario scores, for each major project. The dollar value ($m) per point output of these calculations is detailed in Table 3.10 and provides an indication of the implied dollar value being placed upon the non-financial benefits associated with each project.

Table 3.10 Dollar ($m) per weighted KRA index point

Major property project	Dollar ($m) per Weighted KRA Index point
Townsville	$7.12m
Cairns	$1.11m
Hervey Bay	$2.59m
Maryborough	$4.11m
Rockhampton	$10.37m
Mackay	$4.43m
Average ($m) per point	**$4.93m**

Source: PB analysis.

PB notes, as detailed in Table 3.10, that the dollars per weighted KRA index point differ significantly between business cases to achieve the preferred option in each case. PB is of the view that ideally, the dollar value per weighted KRA index point should be consistent across all business cases, to provide a benchmark with which to compare projects. PB notes that the average dollars per weighted KRA index point is $4.93m across the 6 major projects. In PB’s opinion, $4.93m per weighted KRA index point is a reasonable indicative benchmark to compare the major projects. PB notes that Townsville ($7.11m) and Rockhampton ($10.24m) are significantly higher than this benchmark, indicating that the value of non-financial benefits compared to financial costs (using Ergon Energy’s business case methodology) is relatively low for Townsville and Rockhampton compared to the other four major property projects.

Given this additional insight into these two projects, PB reviewed the new documentation relating to the prudency of capital expenditure at Townsville and Rockhampton provided in

Ergon Energy's revised proposal. PB notes the following statements by Lend Lease in its site assessment report[199] prepared for the existing Dalymple Road depot in Townsville:

- "site safety has been compromised as the depot has grown. The present mix of pedestrian activities and dangerous vehicle movements is unsafe at this depot"[200]
- "the site is at full capacity for its existing mix of operations and does not allow for expansion of group operations which is required to meet future growth projections"[201].

PB notes the following statements by Lend Lease in its site assessment report[202] for the existing Richardson Road Depot in Rockhampton:

- as the operations on the site have expanded employees are now being accommodated in temporary buildings on the truck parking and hardstand storage areas at the rear of the site. The safety demarcation on the site is now being compromised as staff access to these buildings is mixed with truck circulation and forklift paths and is a safety issue[203].
- 'the site is over occupied and operations are being severely compromised. The site has no growth potential and future expansion of operations should take place on the Glenmore Road site (the site proposed in Ergon Energy's regulatory proposal). The Tads group need to be consolidated as much as possible on the one site for operational efficiency and this can be achieved on the Glenmore Road site. This would free up space on the Richardson Road site for consolidation of operations in the existing buildings which are in reasonable condition and suitable for purpose'[204].

PB considered the above information in light of the fact that Townsville and Rockhampton are the largest individual capital expenditure projects in Ergon Energy's revised proposal, and the least cost efficient of all major property projects in terms of dollars per weighted KRA index point. Based on this information, while it is clear that it would be prudent to address these issues, in our view the site assessment information does not demonstrate the efficiency of the proposed capital expenditure as Ergon Energy has not considered any alternative options to address these safety and capacity issues. Noting that Ergon Energy's current sites and property assets in Rockhampton are identified as fully occupied[205], additional alternative options for Rockhampton for example could involve the movement of activities away from the Richardson Road Depot to a new site (either leased or purchased) in Rockhampton. PB notes that no information is provided in Ergon Energy's revised proposal for such an option, or others to address safety issues such as improved management, separation and identification of vehicle and pedestrian access routes.

Conclusion

In PB's opinion the business cases, site condition assessment reports and other supporting information provided by Ergon Energy demonstrates that the Corporate Property Strategy is up to date and relevant. PB is also of the view that the prioritisation process is appropriate in general and that, with the exception of Townsville and Rockhampton, the approach to

199 Lend Lease, Site Assessment Report – Ergon Energy, Townsville – Dalrymple Road Depot and Ingham Road Site, December 2009, p.5
200 Ibid, p.5.
201 Ibid.
202 Lend Lease, Site Assessment Report – Ergon Energy, Rockhampton – Glenmore Road Depot and Richardson Road Depot, December 2009
203 Ibid, p.5
204 Ibid.
205 Ergon Energy, Rockhampton Redevelopment Business Case, 16 December 2009, p7.

considering alternative project options is reasonable. PB also considers that Ergon Energy has demonstrated that the proposed program of works in the next regulatory control period is deliverable.

Having reviewed the new information provided by Ergon Energy in its revised proposal, PB is now satisfied that Ergon Energy has demonstrated that all major project expenditure, with the exception of Townsville and Rockhampton, are prudent and efficient. On this basis PB recommends capex be provided based on an allowance for routine investment works and all major property projects with the exception of Townsville and Rockhampton.

With respect to Townsville and Rockhampton, considering: the magnitude of the variance of the dollar per weighted KRA index point above the average; the sensitivity of Townsville and Rockhampton to the weighting between financial and non-financial criteria; and in the absence of additional alternative options for these large capital expenditure projects; PB is of the view that Ergon Energy has not demonstrated that they are prudent and efficient. Hence we recommend that they be removed from the allowance for the next regulatory control period.

PB's revised recommendation in relation to property expenditure is outlined in Table 3.11. PB notes the following in relation to Table 3.11:

- the AER draft decision figure of $198.8m was calculated by removing $188m from Ergon Energy's original proposal of $386.8m
- Ergon Energy's revised proposal of $388.2m differs from the aggregate of its yearly revised expenditure due to rounding errors
- the PB adjustment of $148.0m has been generated by removing the escalated ($09-10) capex for Rockhampton ($55.0m in real $07-08 escalated to $79.8m) and Townsville ($47.0m in real $07-08 escalated to $68.2m), in accordance with Ergon Energy's proposed capex by year for these major projects.

Table 3.11 PB revised property capex recommendation ($09-10)

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
AER draft decision	39.8	39.8	39.8	39.8	39.8	198.8
Ergon Energy revised proposed	128.2	106.9	80.4	34.4	38.4	388.2
PB adjustment	(29.0)	(21.8)	(43.5)	(21.8)	(31.9)	(148.0)
PB recommendation	99.2	85.1	36.9	12.6	6.5	240.3

Source: PB analysis.

4. Forecast opex

In this section PB reviews the following matters in relation to Ergon Energy's revised forecast opex proposal:

- Pole inspections
- Service inspections overlap
- Vegetation management – cumulative growth
- Keys and locks
- Removal of old poles
- Access track work volume
- Forced maintenance volume
- Alternative control – metering and customer service
- Demand management PM
- GSL payments – forecasting methodology.

4.1 Pole inspections

PB is required to review in detail, and provide advice on the prudence and efficiency of the preventative maintenance costs (maintaining the pole inspection periodicity rate of 4 years) in section 11.4.3.3.1 of Ergon Energy's revised proposal.

As part of its draft decision, the AER reduced Ergon Energy's forecast preventive inspection maintenance for poles by $15.4m. It considered that Ergon Energy has been overly conservative in its approach to risk regarding the possible failure of its wooden poles and that given the current reliability of the poles, and Ergon Energy's comprehensive knowledge of the assets arising from the previous inspection based on a 3 year cycle, increasing the inspection cycle further from 4 to 4.5 years would result in opex forecasts that better reflect the costs of a prudent operator.

4.1.1 Revised proposal and new information

Within its revised proposal, Ergon Energy has sought to clarify the position put forward in its original proposal stating that it considers the four year inspection cycle is prudent and there exists insufficient information for Ergon Energy, PB or the AER to safely recommend an extension beyond this period.

In particular, it has addressed each of the AER's concerns in turn, stating that:

- there is insufficient information to justify an extension to the pole inspection periodicity to 4.5 years

- standards are not intended to justify lesser performance
- 4.5 year inspection periodicity will adversely impact pole failure rate
- due to the nature of Ergon Energy's network, a pole inspection periodicity of 4.5 years will not allow all poles to be inspected within the regulatory timeframe
- the drivers of pole degradation for Ergon Energy and ENERGEX are not similar
- a reduction in preventive maintenance expenditure can not be considered in isolation.

Ergon Energy's assertions were supported by an independent report prepared by Huegin, where PB has extracted the following key findings:

- by 2010 Ergon Energy will not have a sufficient understanding of their assets to justify an increased inspection periodicity
- for the purposes of comparing appropriate pole maintenance periodicities, Ergon Energy and Energex are dissimilar. Further, the environmental conditions (a key driver of pole hazard rate) for Ergon Energy are both more severe and more variable
- extending the pole inspection periodicity will have an unknown yet detrimental impact on the pole hazard rate
- extending the pole inspection periodicity to four and a half years will not allow a sufficient operational margin to ensure all poles are inspected within the five-year regulatory timeframe
- extending the pole periodicity will require increased expenditure on corrective (and potentially forced) maintenance.

4.1.2 PB findings and recommendation

The key premise of PB's original recommendation to extend Ergon Energy's inspection cycle from 4 to 4.5 years is based on the balance of evidence presented that indicates historically Ergon Energy has realised a material economic efficiency is achievable whilst at the same time improving the reliability performance of its pole population.

Specifically, and as presented in PB's original report - since March 2006 at the time when Ergon Energy increased its inspection cycle from three to four years, the 3-year moving average of unassisted pole failures has improved from approximately 99.993% to 99.997% as of August 2008. This constitutes a 50% reduction in annual failures from around 70 per annum per million poles to 30, and this can be compared with the minimum target of 100 failures stipulated in the Queensland Electrical Safety Office's Code of Practice for Works. PB does note that a marginal reduction in performance has been observed for the subsequent 6 month period to February 2009.

Whilst a direct relationship between unassisted pole failures and inspection cycles has not been definitively established, in PB's view this long term trend of improvement is associated with Ergon Energy's understanding of its pole population and its asset management practices, including a high nailing to replacement ratio as informed by its original three-year inspection cycle.

In PB's view, as part of its revised proposal, Ergon Energy has provided no new material to substantiate that the unassisted failure rate is likely to materially change as an outcome of the decision to move to a 4.5 year inspection cycle.

PB's review of the position put forward by Ergon Energy as part of its revised proposal is outlined against each of the key issues raised:

'there is insufficient information to justify an extension to the pole inspection periodicity to 4.5 years'

PB recognises the lack of information available to allow Ergon Energy to establish a prescriptive failure forecasting (P-F interval) model for its pole population, and notes it is proposing to move to a formalised Reliability Centred Maintenance (RCM)[206] approach to maintenance strategy development incorporating Failure Mode and Effects Analysis (FMEA)[207], subject to the availability of accurate failure data and adequate statistical analysis tools.

However, PB highlights that asset performance in terms of unassisted failure results is readily available and well documented and that this constitutes sufficient critical information to make asset management and maintenance based decisions. This position is taken given that the minimum reliability standard within the Code of Practice for Works has been established in the context that the maintenance system and practices of a Queensland electricity entity should be designed to achieve the specified minimum levels of reliability[208].

The lack of knowledge of the P-F interval for the installed population has not restricted Ergon Energy increasing its inspection periodicity in the past. Ergon Energy as an experienced asset manager has used its discretion to move from three to four year inspections as recently as 2006 on the primary basis of data it had captured. Ergon Energy states in its asset equipment plan that[209]:

> *"an initial 3 year inspection cycle was implemented in July 2001 to fast track assessment of the state of the Ergon Energy overhead line network, capture asset data, and introduce a new regime for ground line inspection of poles. The current 4-year cycle was introduced in July 2006 and at this point in time, the asset inspection cycle will remain until maintenance and data issues are resolved."*

PB considers the extension of the inspection period to 4.5 years is consistent with Ergon Energy's longer term strategy to move to a risk based maintenance strategy and is possible given the reliability performance of the assets and the increased knowledge of the assets it will have gained by 2010 since its transition to the four year inspection cycle in 2006. As discussed in the Code of Practice, the inspection intervals may be based on documented knowledge of the durability rating, preservation type, inspection procedures, age, performance of the poles, fungal decay, termite risk and so on. PB would expect that Ergon Energy holds this level of information for its assets given the observation that by the start of the next regulatory control period it will have completed two full cycles of inspections, and that it has stated:

206 RCM is is a systematic approach to defining a routine maintenance program composed of cost-effective tasks that preserve important functions, Wikipedia

207 FMEA is a procedure in operations management for analysis of potential failure modes within a system for classification by severity or determination of the effect of failures on the system, Wikipedia

208 Electrical Safety Office, *Electrical Safety Code Of Practice 2010 Works*, part 5.1, p.36

209 Ergon Energy, *AEP - 02 Poles Ver 0.9g.doc*, p.12

> *".. inspection of poles is performed to meet the regulatory requirement of a 5 year inspection cycle as detailed in Regulation 1 . The Regulation allows for a longer inspection cycle based on a detailed risk driven engineering assessment but such an assessment is unlikely until full collection of cycle data is complete and further engineering analysis performed."*[210]

PB recognises Huegin's observation that 37.4% of poles in its Ellipse system do not have an exact date of construction associated with their records[211]. Based on PB's review of the AEP 02 – Poles, it is acknowledges that 15% of Ergon Energy's poles have ages assigned based on a lognormal distribution peaking in 1960. PB would contend that the exact age or date of manufacture is not as relevant as the data Ergon has collected in regards to these poles over its previous two inspection cycles.

'standards are not intended to justify lesser performance'

PB considers a prudent and efficient operator weighs up both the costs and performance outcomes of its asset management and maintenance practices. In the context that the performance of Ergon Energy's assets considerably exceeds the established standards, and that it has been shown in the past that lesser performance is not an outcome of increased inspection cycles, PB considers the extension is consistent with the actions of a prudent and efficient operator.

PB also notes Ergon Energy's claim that extending the inspection cycle amounts to a reduced maintenance standard and a subsequent increase in failure rate. PB confirms that its recommendation does not propose to reduce the maintenance, design or performance standards applicable for the wood pole population during inspections.

PB considers that the economic implications considered in conjunction with the excellent reliability performance of the wood pole fleet is sufficient information to require a DNSP seeking to efficiently minimise costs to extend the period to 4.5 years.

'4.5 year inspection periodicity will adversely impact pole failure rate'

As measured by unassisted wood pole failures, Ergon Energy's history of reliability performance does not support this argument. Furthermore based on Ergon Energy's practices of extending pole life by the use of steel pole nails or stakes, and its replacement program, which leverage of its comprehensive Defect Classification Manual introduced in September 2007 and the detailed end to end processes for Asset Inspection and Defect management, PB concludes that there is limited evidence to suggest that the extension of pole inspections to 4.5 years will adversely impact pole failure rates.

'due to the nature of Ergon Energy's network, a pole inspection periodicity of 4.5 years will not allow all poles to be inspected within the regulatory timeframe'

PB highlights that the minimum regulatory timeframe of 5 years outlined in the Code of Practice is only applicable in the absence of documented knowledge of pole performance. PB considers that such a regulatory requirement is not directly applicable for Ergon Energy as: it has documented knowledge of its pole assets; its safety obligations are being met; and therefore it has the discretion to inspect poles at any interval it deems appropriate.

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210 Ergon Energy, *AEP - 02 Poles Ver 0.9g.doc*, p.7
211 RP938c_Huegin Report for EE_V1.1 incl Appendix A_12Feb10.pdf, p.76

Furthermore, PB considers that the 6 month buffer to allow for delays caused by environment and wet weather (the key risks identified by Ergon Energy as causing potential delays in inspections) is reasonable and notes that Ergon Energy has flexibility in its design of inspection periods across the various high and low risk areas of its network. The approach recommended by PB would ensure that the average inspection frequency is increased to and maintained at 4.5 years - appropriate works management processes could allow some higher risk area poles to be inspected more often and some newer, better condition poles to be inspected at periods of greater than 4.5 years. A well co-ordinated maintenance program should ensure that all poles can be inspected in the designated timeframes given the six month buffer proposed, irrespective of the impacts of environmental and weather related influences.

'the drivers of pole degradation for Ergon Energy and ENERGEX are not similar'

PB accepts that the drivers of pole degradation and the environmental concerns relevant to Ergon Energy's wood pole population are not similar to those experienced by ENERGEX, particularly in the context of the nine climatic variables referenced by Huegin.

These matters contributed to PB's recommendation that a different inspection cycle to that employed by ENERGEX be used. The extension of only half a year in inspection cycles was informed based on a balanced view of the preventive maintenance cost savings, the limited impacts this is anticipated to have on degrading reliability performance, and the acknowledged strategic intent to extend the cycle by Ergon Energy, and ultimately move to a more direct condition based maintenance approach.

'a reduction in preventive maintenance expenditure can not be considered in isolation'

Ergon Energy has stated that the extended inspection cycle duration will result in an increase in the number and severity of failures and the prevalence of defects and that the incremental costs of such corrective and forced maintenance have not been appropriately accounted for as part of the AER's draft decision.

For transparency, Ergon Energy has assumed the following assumptions as part of its forecast opex for its pole fleet:

- a constant unassisted pole failure rate of 0.003%
- a constant nailing rate of 1.33%
- a constant replacement rate of 0.46%

While no direct relationship between inspection cycles and unassisted pole failures has been established, Ergon Energy's historical experience suggests that as inspection cycles were extended in the past, a significant improvement in unassisted pole failures was realised. PB considers that the rate of nailing increase in the past (which is incorporated into the forecasts) has been primarily informed by the update to the pole nailing process and defect criteria issued in September 2007. Consistent with Ergon Energy's forecast of constant nailing rate, PB does not anticipate any material increase in this rate through the extension of the inspection cycle by six months as there is no change to the defect standards and no evidence that Ergon Energy will be extending the inspection cycle significantly enough to move into an area where the decay rates are likely to cause a material increase in either the unassisted failures or its condition to inform its serviceability.

In PB's view, Ergon Energy has set a clear precedence in 2006 that it has sufficient knowledge of its assets to change its wood pole inspection cycles. The three-year moving average unassisted pole failure rates have been improving for a number of years and is very low compared with the minimum safety standard. On this basis, PB considers there is a real economic opportunity to maintain the existing reliability performance by continuing then routine inspections, albeit at a more efficient and slightly longer time interval of 4.5 years.

PB maintains its view that the performance of Ergon Energy's wood pole supporting structures for lines as measured by the key metric of unassisted failure rates is at an industry leading level and that the businesses current procedures for inspecting, assessing, marking and maintaining poles is achieving standards well above those required by the safety guidelines. There is opportunity to capture further economic benefits, as has been realised by Ergon Energy as part of its recent asset management decisions, and PB recommends the strategy is extended such that a 4.5 year average inspection cycle is adopted for wood poles, and that the opex allowance is reduced in accordance with the AER's draft decision as per Table 4.1.

Table 4.1 Recommended preventive maintenance opex associated with pole inspections

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
Ergon Energy revised proposed	3.4	3.4	3.4	3.4	3.4	17.0
PB adjustment	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(17.0)
PB recommendation	-	-	-	-	-	-

Source: PB analysis.

4.2 Service inspections overlap

PB is required to review at a high level, and provide brief advice on the prudence and efficiency of the preventative maintenance costs in section 11.4.3.3.2 of Ergon Energy's revised proposal, having regard to the proposition that the costs of reducing expenditure of the "coincident visual inspection" program will outweigh the benefits achieved from this reduction.

As part of its original proposal, Ergon Energy included an allowance within its preventive maintenance program to allow for an initial implementation pilot program for customer low voltage service full inspections in 2010-11, followed by the systematic roll-out of full inspections on a 12 year cycle from 2011-12. The AER proposed a reduction of $1.7m to take into account a reduction in the number of coincident visual inspections in order to offset the increase in full inspections based on the premise these inspections delivered similar outcomes.

4.2.1 Revised proposal and new information

As part of its revised proposal, Ergon Energy contends that the full inspection program and the visual inspection program are dissimilar and there is no tangible overlap. Specifically, it states that:

- the two programs address different failure modes

- the two programs consist of different activities at different frequencies
- the full inspection program will incur higher costs than those originally estimated if the visual inspection is incorporated into the full inspection
- the full inspection program does not include visual inspection along the full length of the service wire or at the point of mains supply, in that it is restricted to a visual inspection and electrical testing at the customer connection
- the cost of excluding services inspected through the full inspection program from the visual inspection will exceed the savings identified by PB due to the required enterprise resource planning solution changes and ongoing administrative costs.

Ergon Energy therefore proposes that its original forecast of the volumes for visual inspections be retained rather than offset by the number of full inspections, after the pilot program is completed in 2009-10.

4.2.2 PB findings and recommendation

In consideration of the further information presented by Ergon Energy, PB makes the following observations:

- The ground based visual inspections undertaken on a four year cycle have been costed at $11.68 each and include: the visual inspection of overhead services; visual inspection of the above ground section of underground services that are attached to a pole in overhead areas; identification of targeted service types and constructions that no longer adhere with current standards that may need to be replaced in future maintenance initiatives; identification and recording of defects on Ergon Energy owned assets; and communication to property owners or occupiers of defects observed during inspections on the customer owned assets at the point of supply.
- The full inspections undertaken on a twelve year cycle have been costed at $150 each and are restricted to visual inspections and electrical testing at the customers connection, in order to identify and address neutral connectivity defects and target the removal of bare wire, neutral screen concentric and parallel web twisted service cables.
- Given the common elements of the tasks (such a visiting the location of the service and the visual inspection of the overhead service), PB maintains that there are opportunities and economies of scale available to Ergon Energy to complete both the full inspection and the visual inspections in a co-ordinated manner as part of the full inspection, notwithstanding that the full inspection is focussed on the custoerms connection and the visual inspection is focussed on the supply point and the service itself.

PB also considers that given the estimating process used to establish the full inspection program costs (where reference is made to that used by ENERGEX, adjusted for travel costs), the incremental cost of undertaking the visual inspection is expected to be negligible. Specifically, it is likely that in the majority of cases the inspector will be required to pass along the entire length of the service wire in order to undertake the inspection and testing at the customers connection. PB believes the full inspection should be inherently designed to account for the visual inspection.

In regards to the claims by Ergon Energy that the cost of excluding services inspected through the full inspection program (twelve years) from the visual inspection (every four years) will exceed the savings identified by PB due to the required enterprise resource planning solution changes and ongoing administrative costs, PB appreciates that there will be a need to align and co-ordinate the varying inspection cycles, but we anticipate that an effective works management system will perform the necessary co-ordination without an increase on-going costs.

PB considers that an asset manager seeking to deliver efficient and minimised costs would reduce the coincident visual inspections of customer services at the same rate that the full inspections are increasing, given that they should be designed to achieve similar outcomes, after the completion of the pilot program in 2009-10.

Table 4.2 Recommended preventive maintenance opex associated with inspections of overhead services

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
Ergon Energy revised proposed	0.3	0.3	0.3	0.3	0.3	1.7
PB adjustment	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(1.7)
PB recommendation	-	-	-	-	-	-

Source: PB analysis.

4.3 Vegetation management – cumulative growth

PB is required to review at a high level, and provide brief advice on the prudence and efficiency of the preventative maintenance management costs associated with endangered species, declared plants and cultural heritage in section 11.4.6.4.2 of Ergon Energy's revised proposal, having regard to the new information provided, including Ergon Energy's proposition that Wilson Cook's step change criteria test applied in the AER's 2009 NSW DNSPs Determination should be used in assessing this proposal.

As part of its draft decision, the AER removed the effect of cumulative growth factors incorporated by Ergon Energy in relation to the management of endangered species, declared plants and cultural heritage resulting in a downwards adjustment of $4.7m to the forecast of preventive vegetation management.

4.3.1 Revised proposal and new information

As part of its revised proposal, Ergon Energy has reviewed the justification for its forecast cost increases. It has re-iterated that the costs are driven by: continually changing compliance requirements; recently enacted legislation; and the growing trend for government agencies to demand more information and to impose stricter conditions. It also notes that the forecast changes are due to drivers outside the control of the business and that the step change in expenditure is prudent and efficient based on precedents set for step changes as part of the 2009 NSW Distribution Determination.

Ergon Energy contends that failure to provide increased allowances for emerging issues in these areas is likely to result in significant funding shortfall or non-compliance with Queensland legislation and is seeking to have the adjustment reinstated.

4.3.2 PB findings and recommendation

PB has considered the revised justification for cumulative growth escalators applied by Ergon Energy to its activities associated with endangered species, declared plants and cultural heritage as part of its preventive vegetation maintenance forecasts. In PB's view Ergon Energy has still failed to provide any detailed justification or information to support its approach. No evidence or description of increased activities during the current regulatory control period has been provided, nor any insight into the nature of increasing and emerging requirements anticipated by Ergon Energy to be driven by the various government agencies. Given this lack of supporting detail, PB considers the forecast increases are speculative in nature, and not linked to any clearly identified factors associated with changing compliance requirements related to endangered species, declared plants and cultural heritage. The lack of detail in describing the increased obligations on Ergon Energy provides no opportunity to verify if the $100k per annum increase in each of the three areas is prudent or efficient.

PB also notes from Ergon Energy's NARMCOs model that:

- it appears significant step changes have been incorporated into the 2009-10 allowance compared to the 2008-09 figure – and this has been carried forward by as part of its recommended expenditure
- no cumulative growth has been incorporated into the similar cultural heritage allowances included as part of the access track preventive maintenance.

In regards to Ergon Energy's assertion that the increased costs should be accepted given the precedence of step changes accepted in NSW due to factors outside the control of the business, PB considers the cumulative growth increases sought by Ergon Energy do not constitute step changes because as advised by Ergon Energy they are driven by anticipated continual changes in obligations rather than through any specific trigger or event.

PB maintains that the proposed level of expenditure in 2010-11 is more reflective of a prudent and efficient level of expenditure and recommends to the AER that its original reduction be maintained.

Table 4.3 Recommended preventive maintenance opex associated with cumulative growth in vegetation management

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
Ergon Energy revised proposed	0.9	0.9	0.9	0.9	0.9	4.5
PB adjustment	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(4.5)
PB recommendation	-	-	-	-	-	-

Source: PB analysis.

4.4 Preventive maintenance - keys and locks

PB is required to review at a high level, and provide brief advice on the prudence and efficiency of the preventative maintenance costs in section 11.4.6.5.1 of Ergon Energy's revised proposal, having regard to corrections to Ergon Energy's standard keys and locks forecast amount and new information and other supporting documentation provided.

As part of its original proposal, Ergon Energy included an allowance within its preventive maintenance program for the extension of a program to standardise keys & locks from legacy corporations to improve substation security and upgrade locks on gates in access tracks and equipment. The AER proposed a reduction of $8.4m from the proposed $9.2m as part of its draft decision due to the lack of supporting information, including a lack of risk assessment and/or economic evaluation.

4.4.1 Revised proposal and new information

As part of its revised proposal, Ergon Energy has undertaken a detailed review of the forecasting assumptions for its keys and lock program, and included its original business case[212] and details of unit costs established through competitive tender processes[213].

It has clarified that the revised program takes into account the installation of 40,863 locks based on:

- one lock per four kilometres of track
- two locks per padmount substation
- 1.5 locks (on average) per ground enclosed substation
- one lock per air-break switch
- 2,000 keys to be supplied
- co-ordinating the roll-out with existing inspection and maintenance programs

The revised proposal represents a reduction of approximately $6.0m from the original proposal.

4.4.2 PB findings and recommendation

In consideration of the new information presented by Ergon Energy, in particular the transparent scope of works and the referenced sources for the cost estimates, plus the historical business case[214] which outlines options considered and the security, health and safety risks associated with unauthorised access to Ergon Energy's sites, PB considers the revised preventative maintenance opex associated with the key and lock program is prudent and efficient.

212 Document RP916c, *RP916c_EE_NIRC Business Case_Key & Lock Replacement_V6_23Aug07.doc*

213 Document RP910c, *RP910c_EE_Provision of Keyed Locks Evaluation_Contract 2007-0157-T_15May08.doc* and Document RP911c, *RP911c_EE_Provision of Keyed Locks 2nd Yr Review_Contract 2007-0157-T_Apr09.xls*

214 PB notes the historical business case is associated with zone substations, communication sites and generating sites, and is not directly targeted to access track gates, padmount or ground enclosed substations, or air break switches, however the described security and health and safety risks are relevant for the extended program of works.

Table 4.4 Recommended preventive maintenance opex associated with keys and locks ($m real 09/10, excluding overheads)

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
Ergon Energy revised proposal	0.7	0.7	0.7	0.7	0.7	3.5
PB adjustment	-	-	-	-	-	-
PB recommendation	0.7	0.7	0.7	0.7	0.7	3.5

Source: PB analysis.

4.5 Removal of old poles

PB is required to review at a high level, and provide brief advice on the prudence and efficiency of the corrective maintenance costs in section 11.4.4.3 of Ergon Energy's revised proposal, having regard to the financial policies for the removal of old lines.

As part of its draft decision, the AER reduced Ergon Energy's forecast corrective maintenance for poles by $9.5m. The reduction was recommended by PB in order to remove a scope change specifically included by Ergon Energy for dismantling old lines that have been replaced, as PB believed these should be capitalised and there is evidence Ergon Energy does capitalise such projects.

4.5.1 Revised proposal and new information

Ergon Energy has stated in its revised proposal that the opex allowance has been included to cover situations where the asset being dismantled is no longer required or where the asset is anticipated to continue in service for some time after any related capital project has been completed and will no longer be required.

4.5.2 PB findings and recommendation

In order to better understand the nature and the scope of works proposed by Ergon Energy, PB sought further details on the scope of work and the reasons why an asset would continue in service after the capital project that made it redundant was completed. Ergon Energy's response[215] outlined that the general circumstances envisaged when incorporating the allowance was the situation where: a connection to a customer has been terminated at their request; the assets are subsequently disconnected but remain intact for some time (as obtaining line routes is difficult and other customers may be serviced by the assets); and the decision is then made by Ergon Energy to remove the line and therefore it must be written off and expensed.

In PB's view, this description clarifies that the original scope change included by Ergon Energy in its corrective maintenance forecast was not intended to cover the situation where Ergon Energy chooses to 'dismantle old lines that have been replaced' – rather it is associated with a more general activity of simply 'dismantling old lines'. Regarding this distinction, PB considers the scope change is not reasonable, nor prudent and efficient, since this is an activity that Ergon Energy has been undertaking on an ongoing basis and should already be included within the base year corrective maintenance costs. Ergon Energy

215 Ergon Energy Response to PB.ERG.RRP.03 - Opex Dismantling Old Lines, 19 Feb 2010

has provided no supporting evidence to substantiate the magnitude and timing of the proposed scope change, and PB notes that any decision to dismantle old line is discretionary in nature.

PB recommends the scope change of $9.5m included by Ergon Energy for dismantling old lines is excluded from the total opex forecast.

Table 4.5 Recommended corrective maintenance opex associated with the removal of old lines

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
Ergon Energy revised proposed	2.0	1.9	2.0	1.9	1.7	9.5
PB adjustment	(2.0)	(1.9)	(2.0)	(1.9)	(1.7)	(9.5)
PB recommendation	-	-	-	-	-	-

Source: PB analysis.

4.6 Access track work volume

PB is required to review in detail, and provide advice on the prudence and efficiency of the corrective maintenance costs associated with access tracks as described in section 11.4.6.5.2 of Ergon Energy's revised proposal. Furthermore, although not specifically requested by Ergon Energy, the AER is interested in the application of Wilson Cook's step change criteria test as part of assessing this proposal.

As part of its original proposal, Ergon Energy included a significant step change in both the preventive and corrective maintenance requirements associated with proactive rather than reactive management of access track inspections and the remediation works associated with defects. The AER rejected the extent of the increases in the corrective maintenance allowance on the basis that the magnitude of the step change was not substantiated and that once the existing backlog was managed, future defect rates should diminish. A reduction in the allowance of $27.5m was included in the AER's draft decision for this purpose.

4.6.1 Revised proposal and new information

As part of its revised proposal, Ergon Energy contends that:

- the resulting work volume associated with a defect ratio of 10.5% (as implied by the AER's draft decision) compared with the 18.5% ratio originally sought will be insufficient to manage identified issues and potentially result in non-compliance
- a review by Huegin indicates that the evidence available suggests that a defect rate of less than that applied by Ergon Energy would be hard to justify
- given the four year inspection cycle and the current level of backlogs, efficiency gains from subsequent cycles are not expected to be achieved until the following regulatory control period at the earliest.

Specifically, Huegin's independent assessment aimed to determine historical access track defect ratios, and the likely impact the new inspection regime would have on that defect ratio. Discussions it had with Ergon Energy staff revealed that historical inspections and subsequent remediation work were not entirely made up of reactive work and that the actual defect ratio in the 2008-09 financial year was closer to 37%.

4.6.2 PB findings and recommendation

PB has reviewed Ergon Energy's revised proposal and makes the following specific observations:

- Analysis of detailed historical defect ratios in isolation from unit costs is esoteric in the context that Ergon Energy has clearly advised that its access track corrective maintenance forecast is based on arbitrary information, i.e. *"…started with a bucket-of-money approach ($8M for 2010-11) and worked backwards using an arbitrary defect rate of 18.5% and an arbitrary unit rate of $1,715.20. This resulted in a provision of 4,683 km of work for 2010-11. The defect ratio and unit rate used were not based on any historical data….The AER forecast of access track remediation budget of $8M per annum is considered modest given that it is only double that spent in 2008-09, which represented only a portion of ad-hoc urgent work reported by field staff."*[216]

- The historical unit rate in 2008-09 was $1,073 per km compared with that used as part of the forecast of $1,715. This matter was implicitly incorporated into PB's original recommendation, which focused on the expenditure allowance and not the specific defect ratio or unit rates that were manufactured to support the doubled forecast allowance.

- Huegin's analysis suggests that Ergon Energy accessed over 55% of its entire access corridors population in 2008-09, and that the overall defect ratio was 6.9%. This constituted a defect ratio of 37% for the 10% of the population that was accessed by inspection teams and 0.6% for the 45% of the population that were accessed by other Ergon Energy crews. These figures indicated that Ergon Energy has a much better understanding of the issues associated with access track remediation issues due to the area recently covered.

Given PB's consideration of the information in the revised proposal, we maintain our recommendation to the AER 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.

We also believe that the adjustment reasonably reflects the opportunities for Ergon Energy to realise efficiencies from subsequent inspection cycles as early as 2014-2015, and that the proposed growth rate of 1.6%[217] should not be applied to the access track inspections or remediation volumes given that any new access tracks will already conform to acceptable design standards and should not require remediation within the next regulatory control period.

PB considers its proposed step change increase of 30% effectively passes Wilson Cook's step change criteria test in that it is necessitated by changing compliance obligations associated with OH&S (i.e. the need to use larger and heavier equipment, and the need to

216 EE Response to AER-PB Q.VP.72 - Access Tracks Unit Rates, 25 August 2009

217 This was the original assumption incorporated into Ergon Energy's NARMCOS model, and was the subject of PB's original recommendation to in reduce opex by $4.6m, as per Table 6.28 of its original report. This $4.6m amount contributes to the $27.5m total adjustment.

comply with changing environmental and cultural heritage policy) and to some extent by factors outside the control of Ergon Energy (i.e. inclement weather).

PB recommends the reduction of $27m by applied by the AER, as per Table 4.6.

Table 4.6 Recommended corrective maintenance opex associated with access track remediation

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
Ergon Energy revised proposed	5.4	5.4	5.4	5.4	5.4	27.0
PB adjustment	(5.4)	(5.4)	(5.4)	(5.4)	(5.4)	(27.0)
PB recommendation	-	-	-	-	-	-

Source: PB analysis.

4.7 Forced maintenance volume

PB is required to review in detail, and provide advice on the prudence and efficiency the forced maintenance costs in section 11.4.5.3 of Ergon Energy's revised proposal.

As part of its draft decision, the AER reduced Ergon Energy's forecast forced maintenance by $6.7m (3.3%) on the basis that increase spending on preventive and corrective maintenance was anticipated as well as a significant increase in asset replacement capex and these would have an influence on reducing the likelihood of the need for unplanned repair or restoration work.

4.7.1 Revised proposal and new information

Ergon Energy has not agreed with the logic used by the AER to justify the proposed reduction in forced maintenance. Specifically, it engaged Huegin to review the approach proposed by PB and accepted by the AER and it found that[218]:

- PB assumed that 40% of forced maintenance faults arose from poor plant condition or performance
- PB's assumption is not supported by independent academic research or by Ergon Energy data
- Independent research, as well as Ergon Energy's own data, indicates that external factors (including weather and animals) are the most significant contributor to forced maintenance.

Huegin also presents information from external sources that supports a recent SAHA benchmarking study that found that for Ergon Energy the average faults triggered by equipment and transformer failures from 2003-04 to 2006-07 was around 14%.

218 RP938c_Huegin Report for EE_V1.1 incl Appendix A_12Feb10.pdf, pp.85-88.

4.7.2 PB findings and recommendation

In order to better understand the claim presented by Huegin that the average faults triggered by equipment and transformer failures over the period 2003-04 to 2006-07 for Ergon Energy was 14%, PB reviewed the SAHA benchmarking study referred to by Huegin[219].

PB has inferred from Figure 4.16 of the SAHA report (which specifically excludes the anomalies in the preceding data sets associated with the impacts of Cyclone Larry) that the proportion of faults associated with 'Equipment failure (other)', Transformer Failure 22kV and above', 'Poles down' and 'Conductor down' – represents approximately 30% of the 3-year average period after planned outages have been excluded. 'Other/Unknown' causes also represent 23% of the balance of causes identified. PB considers this information indicates that the average number of faults triggered by poor plant condition or performance is closer to 40% rather than 14.2% as informed by the Huegin analysis.

Regardless of whether the correct figure is 14.2% or higher, PB notes that the 40% factor it assumed was not specifically used in determining the magnitude of the adjustment recommended - it simply informed the approach adopted by PB in undertaking its review.

The key points of clarification are:

- Whilst the aggregate forced maintenance opex was held fixed by Ergon Energy at approximately $27.2m per annum (direct costs) across the next regulatory control period, the modelling implicitly reduced the forced maintenance requirements associated with vegetation management on the basis of its significant increase in preventive and corrective maintenance in this area and its updated strategy. This detail was presented in Figure 6.6 of PB's original report and reproduced in Figure 4.1 below.

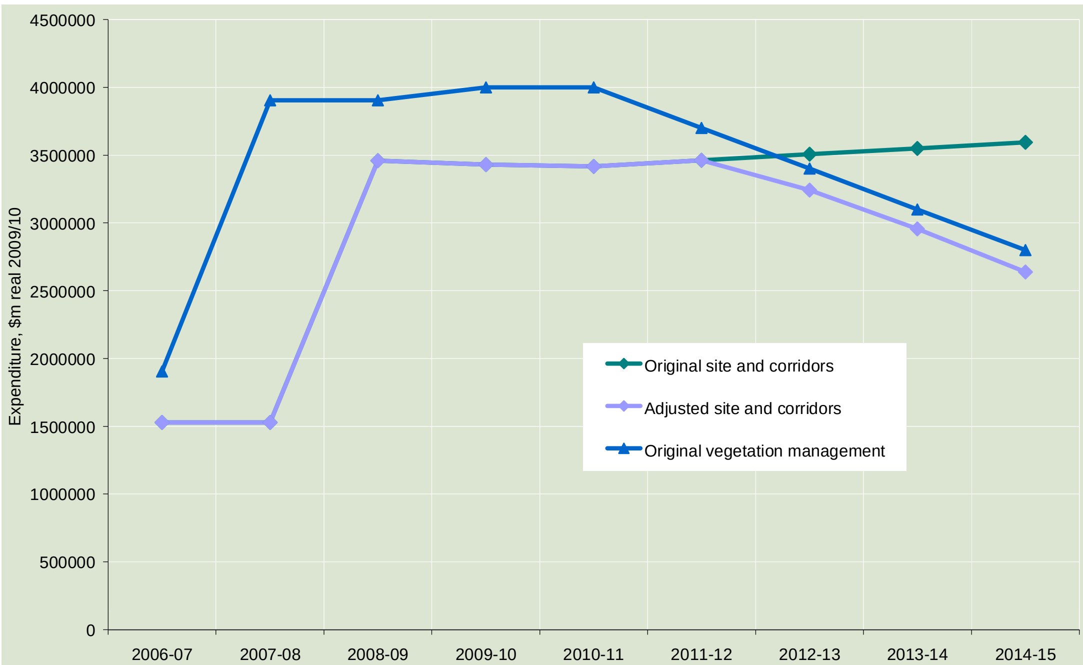

Figure 4.1 Ergon Energy direct costs associated with forced maintenance for sites and corridors

Source: PB analysis and NARMCOS model.

219 PL182c_SAHA_Electricity Distribution Operational Expenditure Review Report_28May08.pdf

- The forced maintenance across 19 of the other 25 asset classes was modelled by Ergon Energy to grow based on the population growth rates used in the NARMCOS model – effectively Ergon Energy was accounting for its increasing asset base

PB quantified its adjustment to the forced maintenance opex allowance by a) removing all growth in the 19 asset classes after 2010-11 where this was modelled by Ergon Energy, and b) applying the same principle to Ergon Energy's corridors and sites forced maintenance opex as it had modelled for the vegetation management asset class, given that it was also introducing a new proactive preventive and corrective maintenance program for these assets. This later adjustment was explicitly shown in Figure 6.6 of PB's original report.

Removal of the growth in forced maintenance in the 19 asset classes contributed to approximately 33% of the total adjustment, and the change to the forced maintenance associated with the sites and corridors contributed the balance.

The key argument presented by PB was that the benefits associated with the significantly increased replacement capex program[220], coupled with the increases in preventive and corrective maintenance opex should ensure that the low defect rate (dictated by random failure modes and external influences) for new equipment should be offset such that no growth in total forced maintenance was necessary in the 19 asset classes were this was included by Ergon Energy. Ergon Energy applied this principle itself to the category of vegetation management based on its new strategy. PB extended this to corridors and sites and removed the growth in the other asset categories. PB maintains that the significant investment in vegetation management itself is likely to result in a material reduction in forced outages due to external factors such as storms and weather, plus a proportion of those with unknown causes.

Noting Huegin's clarification that Ergon Energy has indicated that the high level of unknown triggers in its forced outages indicates that either: patrols need to be more thorough; or more feeders are locking out for transient faults[221], PB believes that these will be addressed by Ergon Energy through a number of mechanisms implicit in its forecast expenditures:

- targeted and increased asset inspection programs, including preventive and corrective maintenance
- improved quality of inspection programs
- strategic vegetation and access track management, noting that wind driven vegetation is a key factor in transient faults
- significant increases in targeted and prioritised asset replacement.

In conclusion, PB maintains that a flat forecast (in terms of direct costs over the next regulatory control period) is prudent and efficient in all asset classes except vegetation management and sites and corridors. In these two asset classes, and notwithstanding the adjustments PB has recommended as an outcome of its review of the proposed replacement capex program, given the significant increases in replacement capex and preventive and corrective opex included in the forecast allowances, reductions in forced maintenance are justified.

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220 In the order of $1.1b, as reduced by 10% as part of PB findings compared with Ergon Energy's original replacement capex proposal.

221 RP938c_Huegin Report for EE_V1.1 incl Appendix A_12Feb10.pdf, p.86

PB recommends to the AER that a reduction in forced maintenance opex of $6.7m during the next regulatory control period is reasonable.

Table 4.7 Recommended forced maintenance opex

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
Ergon Energy revised proposed	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.

4.8 Alternative control – metering and customer service

PB is required to review in detail, and provide advice on the prudence and efficiency of the other operating costs in section 11.4.7.3.1 of Ergon Energy's revised proposal, having regard to corrected information and other supporting documents for meter reading and customer service opex for Standard Control Services.

Ergon Energy included an allowance of $60.4m as part of its June 2009 regulatory proposal for opex associated with activities relating to collecting, processing, loading and publishing meter data for market participants for types 5, 6 and 7 metering installations.

It also included an allowance of $101.3m for opex associated with a variety of expenditure such as customer support, customer advisory services, revenue protection, managing compliance with electrical safety legislation, check inspections, cold water reports and other customer generated queries.

The AER did not accept the forecasts since it could not verify that some Alternative Control Services had not been included in the forecast. Accordingly, the AER reduced the proposed metering allowance by $29.7m, and the customer service allowance by $49.8m. This reduction was informed by the levels of Standard and Alternative Control Services outlined in Document AR272c - Ergon Energy's Customer Care Forecast Report[222].

4.8.1 Revised proposal and new information

In its revised proposal, Ergon Energy has re-iterated in accordance with its written advice to PB and the AER in September 2009[223], that the division of control services in Document AR272c was immaterial and inaccurate and therefore it has not accepted the AER's decision.

Ergon Energy states the sources of error in AR272c arise from: data sources not being in comparable dollar terms; and the classification of services not being in accordance with the approved CAM.

222 AR272c_EE_Customer Care Forecast Report including Meter Read.pdf
223 EE Response to AER-PB Q.VP94 - Opex Reconciliation with Doc AR272c, email 09/09/09

Ergon Energy also:

- states that the actual forecast model (Document PL561c) correctly removed Alternative Control Services (ACS) in accordance with the AER approved CAM, as verified by Huegin's independent review[224]
- provided further details of the reconciliation of costs reported in each of its documents, as prepared by Huegin
- contends and demonstrates through benchmarking undertaken by Huegin that the substitute forecast provided by the AER does not consider the circumstances of Ergon Energy nor reflect a prudent level of expenditure.

Ergon Energy's revised proposal seeks to reinstate the entire $79.5m excluded by the AER from its metering and customer services opex.

4.8.2 PB findings and recommendation

PB has referred to Document AR272c as a key reference in support of Ergon Energy's opex forecast related to customer services and meter reading activities on the basis that this document:

- was presented by Ergon Energy as the document used to inform its budget forecasts[225]
- was prepared by the relevant and responsible workgroup within the business
- not only contained specific details within its appendices of both the Ellipse activities and descriptions, but also of the 130 plus job codes, as well as classifications and descriptions of the types of work contained within the forecast with specific references to the AER's classification of Standard and Alternative Control Services for the business.

PB's key recommendation to the AER as part of its original review was informed by the significant difference between the direct costs input into Ergon Energy's forecast model PL561c of $104.1m (07/08 real) and the Standard Control Service (SCS) costs in AR272c of $52.9m (07/08 real).

In response to a request for further reconciliation on these figures[226], Ergon Energy has advised that elements of seven activities were incorrectly allocated as ACS rather than SCS in the development of forecasts within AR272c and that the updated direct costs are as shown in Table 4.8.

224 RP938c_Huegin Report for EE_V1.1 incl Appendix A_12Feb10.pdf, pp.96-103
225 Figure 58, Ergon Energy Regulatory Proposal to the AER, July 2009
226 EE Response to PB.ERG.RRP.01 - Opex - Other Operating Costs, 01 March 2010

Table 4.8 Correction to customer services and metering SCS (07/08 real)

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
Original AR272c SCS forecast	10.6	10.6	10.6	10.6	10.6	52.9
Corrected AR272c SCS forecast	16.1	16.3	16.6	16.9	17.1	82.9

Source: Ergon Energy AR272c and EE Response to PB.ERG.RRP.01 - Opex - Other Operating Costs.

In consideration of the descriptions of the seven activities, PB is satisfied of the corrections proposed by Ergon Energy resulting in a transfer of the following forecast costs from ACS to SCS:

- QCEMBR - Meter Reading - Cust Meter Read
- QNOMRB - Meter Reading - Cust Meter Read
- Q1011- Meter Query
- Q212 - Alts/Adds-Point of Entry/Service Change
- Q216 - Alts/Adds Whole Current Metering
- Q311 - Reconnect Supply - Vacant Premise
- Q512 - Reconnect after Debt - Unpaid Account

PB notes that our original finding suggested that 50.8% (52.9/104.1) of the expenditure was supported by the reference document, whereas the corrections suggest 79.6% (82.9/104.1) of the expenditure is supported.

Ergon Energy further advised that the outstanding difference is insignificant given the inherent range of error, and was due to:

- comparison of 07/08 real figures with escalated 09/10 real figures
- differences in the effect of shared costs (overheads) between the PL561c and AR272c
- additional errors arising from changes in the classification of services

In consideration of these matters, PB believes that the first two points are not relevant as both the $82.9m and $104.1m expenditures are 2007/08 real figures, excluding any allocation of overheads[227]. PB also considers that Ergon Energy has been provided with the opportunity to outline further detailed corrections to support its original forecasts (in terms of the detailed activities and their classification in Appendix A of AR272c) – but has decided against outlining and correcting the additional errors it is aware of.

In consideration of Huegin's benchmarking, which demonstrates that Ergon Energy's meter reading and customer service opex (by customer numbers) is reasonable compared with allowances approved by the AER for the NSW DNSP's, PB concurs that:

227 These two matters have the effect of increasing the original direct costs $104.1m (07/08 real) by 55% to $161.7m (09/10 real), consistent with the total figure requested by Ergon Energy within the categories of meter reading and customer services.

- given the nature of meter reading activities and the likely accuracy of historical costs in this category, it is likely that significant ACS has not been included in the meter reading category
- customer service activities are more varied than those for meter reading, and comparisons with other businesses are difficult without a detailed understanding of the definition and nature of relevant activities
- Ergon Energy’s original forecast of customer service opex per customer is higher than the three other businesses within the case study.

On this basis of these three points, PB has concluded that based on the historical and forecast trending data, plus the comparative benchmarking information included within Ergon Energy’s revised proposal, it is likely the Ergon Energy’s overstatement of direct costs is attributed to the customer services category rather than the meter reading category, and therefore recommends that its revised adjustment is applicable to this category only.

Given that only 79.6% of the direct costs have been supported, PB has applied this proportion to the original aggregate proposal of $161.7m – to quantify the overall PB recommended adjustment of $33.0m as applied to the customer services opex and presented in Table 4.9.

Table 4.9 Recommended meter reading and customer service opex

	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	-	-	-	-	-	-
PB adjustment - customer services	(6.5)	(6.5)	(6.6)	(6.7)	(6.8)	(33.0)
PB adjustment - subtotal	(6.5)	(6.5)	(6.6)	(6.7)	(6.8)	(33.0)
PB recommendation - meter reading	11.8	11.8	12.0	12.3	12.5	60.4
PB recommendation - customer services	13.3	13.4	13.6	13.9	14.0	68.3
PB recommendation - Subtotal	25.1	25.2	25.6	26.2	26.5	128.7

Source: PB analysis.

4.9 Demand management PM

PB is required to review at a high level, and provide brief advice on the prudence and efficiency of the other operating costs in section 11.4.7.3.2 of Ergon Energy’s revised proposal, having regard to the arguments against the proposed reduction in project management costs for demand management.

As part of its original proposal, Ergon Energy included a five-year incremental project management allowance of $2.6m in addition to the base level of expenditure of $12.8m. These project management costs constituted 25% of the total allowance for demand management initiatives. The AER rejected the incremental allowance on the basis that economies of scale and productivity improvements should be factored into the forecasts.

4.9.1 Revised proposal and new information

Ergon Energy has re-iterated that the AER should recognise the need for ongoing incremental management of the initiatives that will be deployed. It has not, however, provided any new or additional information to support its proposed incremental project management costs.

4.9.2 PB findings and recommendation

In the absence of any new or compelling information to support the incremental project management costs associated with Ergon Energy's demand management initiatives, PB maintains that this element amounting to $2.6m is not prudent and efficient. 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, in particular when taken in the context of the experience captured by the business when rolling out its associated trials and pilot programs within the current regulatory control period.

Table 4.10 Recommended other opex associated with project management of DM initiatives

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
Ergon Energy revised proposed	3.1	3.1	3.1	3.1	3.1	15.4
PB adjustment	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(2.6)
PB recommendation	2.6	2.6	2.6	2.6	2.6	12.8

Source: PB analysis.

4.10 GSL payments – forecasting methodology

PB is required to review at a high level, and provide brief advice on the prudence and efficiency of shared costs as part of other operating costs (GSL payments) in section 11.4.8.1 of Ergon Energy's revised proposal, having regard to the GSL arrangements and Ergon Energy's proposed forecasting methodology.

In October 2009, the QCA published its final decision in regards to its review into customer related Guaranteed Service Level (GSL) targets and the associated payments. It has mandated through the Electricity Industry Code provisions[228] that the value of payments should increase by 30% as of 01 July 2010 and that all payments to customers should be automated rather than customer initiated. Ergon Energy has proposed to increase the 5-year expenditure associated with its GSL payments from $0.3m to $7.5m over the next regulatory control period.

228 Queensland Government, Electricity Industry Code Fifth Edition, section 2.5, 20 November 2009

4.10.1 Revised proposal and new information

The methodology outlined by Ergon Energy in establishing its GSP payment forecast includes:

- maintaining the same level of actual and potential GSL payments determined as part of its current reporting systems, and including a 30% increase in the value of each individual payment, and a 2% per annum customer growth escalation
- sourcing the level of actual and potential GSL payments through existing two monthly reports. The inputs to the calculation of the potential GSL payments are sourced from three separate IT systems: *FACTS*, which includes a record of customer initiated requests; *Feederstat*, which contains network outage information on both planned and unplanned outages and therefore potential GSL payments; and *Facom*, which contains all service related automatic and manual GSL records. These three sources then interact with the *Ellipse* system for allow administrative processing and payments.

  As part of its revised proposal, Ergon Energy provided a copy of both the actual[229] and potential[230] GSL payment monthly reports for October 2009 to outline the data and formula used to calculate the forecast GSL payments of $1.5m per annum given both the number and value of actual and potential GSL payments.

4.10.2 PB findings and recommendation

PB reviewed the supporting spreadsheets provided by Ergon Energy to forecast its potential GSL payments. Specifically, the RP933c spreadsheet shows that over the four month period July to October 2009 - there were 7,883 potential GSL payments identified, with a value amounting to $236k. The key contributing factors to these payments were planned interruptions for business (31%) and residential customers (48%) where sufficient notice (i.e. two days) was not provided.

PB inferred from this relatively small sample of data that the annual potential GSL forecast was $236 x 3 x 1.3 = $920k per annum, where the 'x 3' factor extends the four month period to a year, and the 'x 1.3' factor escalates for the 30% increase in GSL payment obligations. This value was considerably lower than the incremental $1.44m sought by Ergon Energy as part of its revised proposal.

In order to better understand the basis of the forecast, PB sought further details from Ergon Energy regarding its methodology and source data. Ergon Energy's written response[231] included provision of the original model to generate the forecasts based on reports RP932c and RP933c, plus clarification of the submitted documents.

As part of this response, Ergon Energy has confirmed that:

- it has included only those items for which it would have had to pay a GSL on under the new legislation
- it has reworked its forecasts based on 2009 data, providing much more up to date base information.

229 RP932c_EE_GSL Payment Figures_Oct09_23Dec09.xls
230 RP933c_EE_GSL Potential Payment Figures_Oct09_23Dec09.xls
231 EE Response to PB.ERG.RRP.07 - Opex – GSL, 09 March 2010

PB has reviewed the updated information and observed the variations between the 2008 and 2009 data presented – this is summarised in Table 4.11, including PB's calculation of the average between the two years data.

Table 4.11 Potential GSL payments

GSL Type	2008	2009	average	value ($)
Planned Interruptions - Business	3,292	4,768	4,030	65
Planned Interruptions - Residential	10,062	14,726	12,394	26
Connection of Supply	136	73	105	131
Wrongful Disconnection	188	244	216	130
Customer Reconnection	20	12	16	77
Hot Water Supply	7	9	8	147
Appointments	889	851	870	52
Ex Gratia	241	8	125	76
Frequency of Interruption	85	2,566	1,326	104
Duration of Interruption	3,157	3,730	3,444	104
TOTAL - number	18,077	26,987	22,532	
TOTAL – payments ($m)	0.94	1.46	1.20	

Source: Document PRP1002c and PB analysis.

The most significant observation from Table 4.11 is the large increase in potential Frequency of Interruption GSL payments growing from 85 in 2008 to 2,566 in 2009, indicating significant volatility in this measure. In PB's view, the longer run average is more likely to represent the likelihood of potential GSL payments that Ergon Energy can expect to face over the next regulatory control period. On this basis, PB recommends the allowance for increased GSL payments included by the AER be reduced from $1.5m per annum to $1.2m per annum, representing a five year reduction of $1.5m as shown in Table 4.12.

PB considers the inclusion of a 2% per annum escalation to account for the number of new customers potentially impacted by GSL payments is reasonable.

Table 4.12 Recommended opex associated with potential GSL payments

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
Ergon Energy revised proposed	1.5	1.5	1.5	1.5	1.5	7.5
PB adjustment	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(1.5)
PB recommendation	1.2	1.2	1.2	1.2	1.2	6.0

Source: PB analysis.

5. Service Target Performance Incentive Scheme

In this section PB reviews the following matters in relation to Ergon Energy's revised STPIS proposal:

- Reliability of supply – performance targets (MSS-10%)
- Telephone answering parameter – MED's.

5.1 Reliability of supply – performance targets (MSS-10%)

PB is required to:

- respond to the arguments put forward by Ergon Energy that the reliability of supply performance targets should be set at either the more onerous of MSS or past performance rather than Ergon Energy's internal targets (MSS minus 10 per cent)
- review the performance data from 2008-09 to ensure that it is robust and can be relied upon to set performance targets. The AER would expect an assessment of the outcome of relying on five years of data instead of four years of data (including a comparison of outcomes), in particular, its impact on PB's recommendation to set performance targets based on MSS minus 10 per cent or on any other basis
- review the additional major event days (MEDs) which Ergon Energy advised were not initially excluded from its 2008-09 reliability data
- set out the performance targets which it considers are appropriate.

In its draft decision, the AER accepted PB's recommendation that Ergon Energy's internal targets, which are set at the MSS[232] level minus 10%, would be likely to represent the future level of reliability performance, considering the expenditures allowed in the current and next regulatory control periods. On this basis, performance targets for reliability parameters under the STPIS were set equal to the MSS-10% targets, adjusted to include 'service fuse and beyond' interruptions and to exclude planned interruptions as these are not included in the STPIS scheme.

5.1.1 Revised proposal and new information

In its revised proposal, Ergon Energy has indicated[233] that the STPIS targets for reliability parameters should be based on the MSS targets mandated by the Electricity Industry Code, as outlined in the AER's Framework and Approach paper.

Ergon Energy has acknowledged that the MSS targets are not on the same basis as the STPIS targets, as the MSS targets are set for planned and unplanned interruptions and exclude 'service fuse and beyond' outages whereas the STPIS targets are for unplanned interruptions only, and include those classified as 'service fuse and beyond'. Hence, Ergon

232 MSS is the Minimum Service Standards required by the Electricity Industry Code.
233 RP972c_Ergon Energy STPIS Model RevisedRegProposal_11012010.

Energy proposes that the STPIS targets for reliability parameters be set equal to the MSS targets adjusted for the removal of planned outages and the inclusion of ‘service fuse and beyond’ outages.

In its revised proposal, Ergon Energy recalculated the adjusted MSS targets based on actual reliability data for the 5-years to 2008-09.

5.1.2 PB findings and recommendation

In its draft decision, the AER accepted PB’s advice and set the STPIS reliability performance targets to be Ergon Energy’s MSS targets minus 10%, which was reflective of internal business targets adjusted to exclude planned outages. Ergon Energy’s arguments against this approach are discussed below:

Argument 1 - Ergon Energy’s approach to setting the proposed STPIS targets is consistent with that set out in clause 2.5.3 of the AER’s Framework and Approach (F&A)

The Framework and Approach paper states that the performance targets should be set equal to the more onerous of MSS or past performance. Given that the MSS targets are more onerous than past performance, Ergon Energy proposes that the performance targets be set equal to the MSS targets. Ergon Energy’s approach adjusts the MSS targets to remove planned outages and to include ‘service fuse and beyond’ outages. These adjustments are needed to account for the different definitions for the measures under the Electricity Industry Act and the STPIS.

In PB’s view, a further adjustment is required before the STPIS targets can be set equal to the MSS targets. This adjustment is required to account for the different basis of the targets: that is, the MSS targets being ‘at the minimum’ and the STPIS targets being ‘on average’. Such an adjustment is needed because average reliability performance will always be better than the worse performance experienced and hence targets set at the average will always be less onerous then those set to define the worst performance (at the minimum). This adjustment is necessary to avoid Ergon Energy receiving revenue through the STPIS for performance mandated by the Electricity Industry Code.

Argument 2 - Neither the MSS, nor the (unadjusted) MSS-10% internal business targets, were used to develop Ergon Energy’s capital and operating expenditure programs for the 2010-15 regulatory control period.

In its initial report, PB noted that Ergon Energy has recently adopted changed maintenance and planning standards that could be expected to result in improved reliability performance and has also proposed expenditures for reliability improvement projects. PB has been unable to verify whether the increased expenditures associated with the changed maintenance and planning practices and the expenditure for reliability improvement are sufficient to achieve the MSS targets, as Ergon Energy appears to have not reconciled the proposed expenditures with its mandated reliability performance. It is PB’s view, however, that unplanned reliability performance will improve significantly under the expenditures proposed by Ergon Energy.

Argument 3 - Ergon Energy’s MSS-10% internal business targets, adjusted for planned outages, are not based on Ergon Energy’s average historical unplanned performance and do not reflect Ergon Energy’s likely unplanned performance in the next regulatory control period.

PB understands that Ergon Energy has set internal business targets at MSS minus 10% and linked these to its Corporate Performance Agreement and Statement of Corporate Intent. The incentive for Ergon Energy staff to meet the internal stretch targets is through this linkage, which also impacts on annual performance payments.[234] PB acknowledges that these internal targets are not based on Ergon Energy's average historical unplanned performance.

PB notes that Ergon Energy's reliability performance data shows that actual reliability performance varies from year to year, due in part to external factors such as the level of storm activity. Given this variation and noting that the MSS targets are minimum service levels, Ergon Energy's average performance targets must be better than the MSS targets if the MSS targets are to be met. In its original report, PB considered that the difference in the minimum performance standards represented by the MSS targets and the 'on average' performance targets under the STPIS could be informed by the difference between the MSS targets and the internal business targets.

PB has reviewed the relationship between the MSS targets and the internal business targets (MSS-10%) based on the original information provided about the internal target setting[235] and the new information provided in the revised proposal. It considers that if the internal targets are set at the expected 'on average' performance, then a bonus will be receive under the annual performance payments scheme on average 50% of the time. Setting internal targets at a lesser value would not provide sufficient incentive to improve performance as Ergon Energy would need to do nothing in order to receive a bonus in most years. PB has formed the view that the internal targets would need to be set at no less than the average forecast performance in order to be effective. Hence, PB remains of the view expressed in its original report that the MSS minus 10% targets are likely to represent the future 'on average' reliability performance that is required to ensure that the MSS targets are achieve, to an implied level of certainty..

Argument 4 - The (unadjusted) MSS-10% internal business targets are key performance indicators that provide an incentive for management to improve planned outage performance only. Consequently, this incentive will have no impact on Ergon Energy's performance under the STPIS.

This statement appears to be inconsistent with other statements made by Ergon Energy and also with the forecast expenditures proposed for the next regulatory control period. Ergon Energy's statements about its future reliability performance are made in its Annual Network Reliability Performance Report 2008/2009. This report (p. 83 and 84) indicates a strategy to maintain planned interruptions at historical levels by reintroducing live line work to offset an expanded works program and to improve unplanned reliability performance. This is consistent with expenditures proposed in the revised proposal that include specific projects to improve unplanned reliability performance (p. 126) and expenditures associated with changed maintenance and planning standards[236] implemented as a result of the EDSD review in order to improve unplanned reliability performance.

PB has not been able to reconcile the apparent conflict between statements made by Ergon Energy in its revised proposal with those set out in its performance report.

234 EE response to AER-PB Q. AS36, Internal SAIDI/SAIFI targets setting by Ergon Energy, p.2.
235 ibid.
236 In its original report, PB concluded 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 (p. 99).

As part of PB's review of Ergon Energy's revised proposal, Ergon Energy was asked to provide adjusted MSS targets that make an appropriate adjustment for the different basis of the targets. In its response, it stated:

> "*Adjusting the MSS targets in the manner requested would be contrary to the approach outlined by the AER in its final Framework and Approach Paper Application of Schemes Energex and Ergon Energy 2010-15, November 2008."*
>
> *"Ergon Energy has determined its average historical performance, reflective of the exclusions and definitions contained in the AER's STPIS. Ergon Energy has then used that data to adjust its MSS targets to reflect the same exclusions and definitions."*
>
> *"…Ergon Energy considers that this is the appropriate way to determine its STPIS performance targets, and should be accepted by the AER."*[237]

PB notes that this response does not provide new information to support Ergon Energy's position.

In summary, PB does not accept the argument put forward by Ergon Energy that the internal targets for reliability performance should not be used to inform the setting of targets for the STPIS scheme. PB accepts, however, that the relationship between the internal targets and the likely 'on average' performance may not be a direct link.

To better understand how the internal targets should be used to inform the setting of performance targets under the STPIS, PB has analysed Ergon Energy's historical performance to determine the statistical variation about the average. In PB's view, subtracting this variation from the minimum required standard will indicate the 'on average' target that would be required to achieve the minimum standard, to an implicit level of certainty. The calculation performed is shown in Table 5.1, and the methodology is described as:

- normalising the annual reliability data by using the natural log function (this allows the mathematics of the normal distribution to be applied)
- assuming that the minimum standard should be exceeded on average no more often than 1 in 5 years (the length of the regulatory control period), the number of standard deviations that must be achieved is 0.78
- determining the quantity (minutes for SAIDI and interruptions for SAIFI) corresponding to the mean plus 0.78 std deviations. This represents the upper bound of performance that could be expected to be exceeded on average no more often than 1 in 5 years
- convert the upper bound (normalised) to the base by calculating the exponential
- calculating the percentage change between the upper bound and the average performance.

237 EE Response to PB.ERG.RRP.05 – STPIS Ergon Energy email to AER of 26 February 2010.

Table 5.1 Percentage change calculation

Item	Urban	Short rural	Long rural
SAIFI			
Mean of data 03/04 - 08/09	2.15	4.17	7.02
Normalised data:			
Mean of 03/04 - 08/09	0.75	1.41	1.93
0.78 std dev	0.15	0.16	0.17
Upper bound (mean less 0.78 std dev)	0.60	1.26	1.76
Equivalent SAIFI upper bound	1.82	3.52	5.83
% change mean to upper bound	**15%**	**16%**	**17%**
SAIDI			
Mean of data 03/04 - 08/09	193.9	415.5	904.9
Normalised data:			
Mean of 03/04 - 08/09	5.2	6.0	6.8
0.78 std dev	0.18	0.13	0.12
Upper bound (mean less 0.78 std dev)	5.06	5.89	6.68
Equivalent SAIDI upper bound	158.0	360.2	793.3
% change mean to upper bound	**19%**	**13%**	**12%**

Source: PB analysis.

The analysis indicates that the ‘on average’ (STPIS) targets should be set approximately 12% to 19% below the MSS targets to meet the MSS targets, with a probability of not achieving the MSS targets of 1 in 5 years.

In PB’s view, this analysis supports the use of Ergon Energy’s internal targets based on the adjusted MSS-10% as appropriate and conservative targets for the STPIS.

In its revised proposal, Ergon Energy recalculated the adjusted MSS targets based on actual reliability data for the 5-year period to 2008-09. PB has sighted the revised data and confirms that the spreadsheet calculations that now include the 2008-09 year appear correct. The results are slightly more onerous adjusted MSS targets. These revised adjusted targets do not affect Ergon Energy’ internal targets which were set based on data to 2007-08. PB recommends that these internal targets, as set out in the AER’s draft decision, be used as performance targets for the STPIS.

In clarifying its revised proposal, Ergon Energy identified two additional events in its historical data that met the criteria for exclusion and provided an updated calculation for the MSS targets adjusted for planned outages and “service fuse and beyond.[238] Ergon Energy did not provide the raw reliability data; hence PB is unable to confirm the size of the additional exclusions. Ergon Energy did provide the revised unplanned SAIDI and SAIFI information.

PB reviewed the revised reliability data and confirmed that:

- the adjustments made to SAIDI and SAIFI for 2008-09 are consistent with the removal of two days with SAIDI above the MED threshold of 9.8 minutes, as previously determined
- the spreadsheet correctly calculates the removal of planned interruptions, the addition of ‘service fuse and beyond’ interruptions, and the 5-year average performance

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- performance targets based on the 5-year average performance to 2008-09 would be as set out in table Table 5.2 and the adjusted MSS targets as set out in Table 5.3.

Table 5.2 Actual unplanned reliability performance 5-year average

Item	2004-05	2005-06	2006-07	2007-08	2008-09	Ave
SAIDI						
Urban	211.7	240.4	129.8	164.4	147.1	178.6
Short rural	401.0	501.9	315.6	372.4	398.1	397.8
Long rural	952.4	1,024.8	700.0	800.0	836.6	862.8
SAIFI						
Urban	2.082	2.421	1.657	1.826	1.923	1.982
Short rural	4.105	4.877	3.264	3.309	3.897	3.892
Long rural	7.183	8.300	5.190	5.736	6.349	6.552

Source: Ergon Energy RP972c_Ergon Energy STPIS Model Revised 18_Feb_2010.xls and PRP997c_EE_MSS Adjustment for STPIS Targets_15Feb10 (rounding errors accepted)

Table 5.3 Adjusted MSS targets incorporating 2008-09 data

Item	2010-11	2011-12	2012-13	2013-14	2014-15
SAIDI					
Urban	137.3	136.3	135.4	134.5	133.6
Short rural	318.4	313.9	309.4	304.9	300.4
Long rural	755.2	742.6	730.1	717.6	705.0
SAIFI					
Urban	1.839	1.820	1.802	1.783	1.765
Short rural	3.324	3.282	3.240	3.198	3.156
Long rural	6.081	5.999	5.916	5.834	5.752

Source: Ergon Energy RP972c_Ergon Energy STPIS Model Revised 18_Feb_2010.xls and PRP997c_EE_MSS Adjustment for STPIS Targets_15Feb10 (rounding errors accepted)

PB notes that performance targets based on the 5-year average performance would not have been adjusted to account for any reliability improvements completed or planned that have been included in the expenditure program of the regulatory proposal and therefore do not meet the requirements of STPIS clause 3.2.1. PB also notes that actual reliability performance is, on average, not meeting the Adjusted MSS targets.

5.2 Telephone answering parameter – MED's

PB is required to clarify the telephone answering parameter issue in relation to whether Major Event Days (MEDs) should be excluded.

STPIS clause 5.4 states that where the impact of an event is to be excluded from the calculation of a revenue increment or decrement under the 'reliability of supply' component as provided in clause 3.3, the impact of that event may be excluded from the calculation of a revenue increment or decrement for the 'telephone answering' parameter as appropriate. Sub clause 3.3(a) identifies events arising from load shedding, the failure of transmission assets, or imposed obligations that may be excluded and sub clause 3.3(b) identifies MEDs that may be excluded.

In its original proposal, Ergon Energy proposed targets for the telephone answering parameter that did not exclude MEDs. PB found that Ergon Energy could identify excludable events under STPIS clause 3.3(b), but could not identify those telephone calls allowed to be excluded under clause 3.3(a).

In its draft decision, the AER set the target at 77.3% being the average 5-year performance of 76.8% of calls answered in 30 seconds plus the average impact of events under clause 3.3(b) of 0.5%.

5.2.1 Revised proposal and new information

In its revised proposal, Ergon Energy accepts the AER’s revised targets on the basis that it can exclude MEDs from its reported performance.

5.2.2 PB findings and recommendation

PB confirms that Ergon Energy’s revised proposal is consistent with STPIS clause 5.4 and that a performance target set at 77.3% is appropriate.

PB notes that while Ergon Energy does not currently intend to exclude events that accord with clause 3.3(a), these events are infrequent and are unlikely to materially affect the setting of targets based on average historical performance, whether or not they are included in that historical performance, Hence, PB would not be concerned if Ergon Energy altered its reporting in future to exclude events under STPIS clause 3.3(a) and does not believe that AER need include in its determination a restriction on Ergon Energy to only exclude MEDs.