Report
to

QUEENSLAND COMPETITION AUTHORITY

REVIEW OF
ERGON ENERGY'S REVISED CAPITAL AND OPERATING EXPENDITURE SUBMISSION

Final Report 26th April 2005

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1 EXECUTIVE SUMMARY

1.1 Scope

Following the Draft Determination, Regulation of Electricity Distribution ("Draft Determination") by the Queensland Competition Authority ("QCA") in December 2004, Ergon Energy made a revised submission to the QCA in respect to its requirements for Capital Expenditure ("CAPEX") and Operational Expenditure ("OPEX") on 21st January 2005. This report reviews and analyses the revised forecasts and recommends efficient levels of CAPEX and OPEX.

Key inputs into the report were the Draft Determination by the QCA and the Electricity Distribution and Service Delivery Review ("EDSD Review").

1.2 Draft Determination

In its Draft Determination, the QCA made the following allowances for expenditure for Ergon Energy for the period 2005/06-09/10:

Table 1-1: Draft Determination

	$ M	COMMENT
CAPEX	2,296.9	Excludes $173.4M for large but uncertain projects set aside for future discussion.
OPEX	1,052.9	

All costs are in millions of June 2004 dollars, totalled for the 5-year period

The revised submission from Ergon Energy was made in response to the expenditure for CAPEX and OPEX allowed for in the Draft Determination.

1.3 Electricity Distribution and Service Delivery Review

The EDSD Review made 44 recommendations in July 2004, and the Queensland Government has made a commitment that all of the recommendations will be implemented.

Key recommendations include the following:

- Introduction of minimum service standards;
- Introduction of Guaranteed Service Level ("GSL") rebates;
- Targeted improvement to worst performing areas of the network;
- Investigation of options to improve performance of the Single Wire Earth Return ("SWER") system;
- Reduction in load and voltage constraints;
- Improved maintenance programs;
- Improvements to the asset management systems;
- Adoption of more conservative planning criteria and improved network planning;
- Improved Contact Centre performance;
- Improved communications to the public regarding outages;
- Increased numbers of apprentices; and
- Improved performance monitoring and reporting.

Ergon Energy has committed to implementing all of the recommendations that apply to Ergon Energy. This would involve some additional network investment, in both OPEX and CAPEX.

As an outworking of the EDSD Review, the Government has introduced the Electricity Industry Code, effective from 1 January 2005, which will involve some additional OPEX.

1.4 OPEX

In its response, dated January 2005, to the December 2004 Draft Determination, Ergon Energy has accommodated the changes required by the July 2004 EDSD review as well as information obtained since the 2004 submission.

The EDSD recommendations involving operating expenditure are related to the following areas:

- Preparation of a Network Management Plan;
- Improvement to the reliability of long rural, short rural and urban feeders;
- Expediting improvements to maintenance management systems;
- Strategy to reduce the incidence of protection abnormalities;
- Improvements to customer communication during unplanned outages; and
- Development of a resource plan and training strategy.

In reviewing these EDSD recommendations and developing the Network Management Plan, Ergon Energy has identified a number of additional OPEX programs with consequent cost increases. The changes in forecast OPEX are summarised in Table 1-2 and detailed within the following sections of this report.

Ergon Energy has assessed the other recommendations from the EDSD report, and determined that there are no additional operating cost impacts and that there is sufficient funding in the draft determination to achieve these objectives.

BRW has made an assessment of the OPEX programs previously in place and the progress Ergon Energy has achieved towards improving maintenance, maintenance management systems and customer communications. In general, BRW is of the view that Ergon Energy's revised forecast is reasonable. However, small potential efficiency savings in the vegetation program in the order of $4.1M, have been identified and the revised forecast has been adjusted accordingly. BRW also believes that the provision for GSL payments removes the incentive to improve customer service, and has therefore removed these costs from the revised forecast.

Table 1-2: Changes in OPEX Budget Compared to Draft Determination (incl. overheads)

AREA	$M
Draft Determination	1,052.9
EDSD Increase (Vegetation and Reporting only)	81.9
Other Increases – Self Insurance	16.6
EBA OPEX Increment	101.6
Revised BRW Forecast	**1,253.2**

All costs are in millions of June 2004 dollars, totalled for the 5-year period

1.5 CAPEX

The changes in forecast CAPEX contained in Ergon Energy's revised submission, dated January 2005, are summarised in the following table:

Table 1-3: Changes in CAPEX Budget Compared to Draft Determination (incl. overheads)

AREA	DRAFT DETERMINATION	REVISED ERGON ENERGY FORECAST	REVISED BRW FORECAST	COMMENT
Asset Replacement	655.4	655.4	655.4	No change
Augmentation	505.2	700.9	695.2	Section 6.2
Customer Initiated	580.8	683.6	705.1	Section 6.5
Reliability	174.5	205.4	198.0	Section 6.3
Other System	45.9	45.9	45.9	No change
Non-System	335.1	355.1	356.5	Section 6.6
SWER	0	58.7	58.7	Section 6.4
EBA CAPEX Impacts	0	61.7	53.8	Section 6.7
Market Rates	0	49.0	0.0	Section 6.8
TOTAL	**2,296.9**	**2,815.7**	**2,768.7**	

All costs are in millions of June 2004 dollars, totalled for the 5-year period to June 2010

The increases in CAPEX sought by Ergon Energy are attributed to:

- Changed system planning requirements arising from the EDSD Report ($62.7M);
- Updated Maximum Demand ("MD") forecasts ($15.3M);
- Adoption of 10% Probability of Exceedance forecast assumptions as per the EDSE report ($47.0M);
- Additional augmentation work identified from updated plans ($70.7M);
- Additional major customer works, driven largely by expansion in the coal industry ($102.8M);
- Reliability improvement works to meet the new minimum service standards introduced as a result of the EDSD report ($30.9M);
- Increases in building costs ($20M);
- Works on the SWER network as a result of the EDSD Report ($58.7M);
- Impact of the recent Enterprise Bargaining Agreement ("EBA") ($61.7M); and
- Increases in costs for contract and other works ($49.0M).

Of the total increase of $518.7M sought by Ergon Energy, $285.3M is directly attributable to the EDSD report.

A comparison between the Draft Determination, Ergon Energy's 2005 submission and BRW's forecast, with SWER, EBA and Market Rates allocated across the appropriate expenditure areas, is shown in the following table:

Table 1-4: Revised CAPEX forecasts (including allocation of SWER, EBA and Market Rates)

AREA	DRAFT DETERMINATION	REVISED ERGON ENERGY 2005 SUBMISSION	BRW 2005 FORECAST
Asset Replacement	655.4	686.1	682.8
Augmentation	505.2	778.6	722.5
Customer Initiated	580.8	702.3	721.4
Reliability	174.5	235.1	227.2
Other System	45.9	58.5	58.3
Non-System	335.1	355.1	356.5
TOTAL	**2,296.9**	**2,815.7**	**2,768.7**
Eligible for Pass-Through	173.4	487.6	400.0

All forecast figures are in June 2004 dollars. (millions)

The main differences between Ergon Energy's and BRW's forecasts result from:

- The adoption by BRW of different unit rates;
- The exclusion of increased sub-transmission and substations costs; and
- The correction of several errors in Ergon Energy's submission.

1.6 Enterprise Bargaining Agreement

Coincident with the establishment of a new EBA in 2005 were a number of recommendations from the EDSD report requiring both DSNPs to develop a resource plan and implement a training strategy to overcome some specific difficulties.

Ergon Energy have included in its submission a component of 0.5% of the current EBA representing an increased productivity payment. BRW is of the view this should be absorbed as an efficiency gain and consequently has removed it from the revised forecast. BRW's revised forecast is $155.4M. Although this appears generous, BRW appreciate that there is a need to attract and retain staff in order to resource proposed capital and operational programs for the next regulatory period.

BRW considers that the forecasts of the additional costs associated with the new EBA are reasonable.

1.7 Resourcing

Ergon Energy has updated its resource plan that details its capacity to find the resources (both internal and external) required for the delivery of the 2005/06 works program and outlines the approach for delivery of the remainder of the regulatory period. Ergon Energy has demonstrated its capacity to deliver on the 2004/05 works program, and is actively implementing its strategies relating to internal staffing and external contractors.

Although BRW is reasonably confident of Ergon Energy's capability to resource the forecast workload over the forthcoming regulatory period, there is some risk that Ergon Energy will not be able to deliver an expenditure program of this size. To mitigate this risk, BRW recommends that the QCA allow for only 90% of the CAPEX (i.e. $2,491.8M) to be initially included in Ergon Energy's revenue cap, with provision for Ergon Energy to increase this amount (up to $2,768.7M) on demonstration of the need and capacity to wisely invest the full amount.

2 SCOPE AND METHODOLOGY

2.1 Scope

Following the draft determination by the QCA, the distributors Energex and Ergon Energy, made revised submissions to the QCA in respect of their requirements for CAPEX and OPEX.

BRW's scope of works was as follows:

- Review and analyse the revised CAPEX and OPEX forecasts submitted by each of the two distributors, including on-site discussions with the distributors;
- Recommend efficient levels of CAPEX and OPEX;
- Assess key factors that could affect the capacity of the distributors to appropriately use the recommended expenditure; and
- Present the findings in a consolidated report to the QCA for each distributor.

2.2 Methodology

The review was conducted in five stages:

Stage one - Data Collection;

Stage two - "Desk Study" Review;

Stage three - Review of Significant Issues;

Stage four - Preparation of Draft Report; and

Stage five - Preparation of Final Report (this report).

Unless stated otherwise, all figures contained in the report are in June 2004 dollars.

2.2.1 Data Collection

This stage involved gaining a detailed understanding of the changes that had occurred since the previous submission was prepared in 2004. A range of information was collected, collated, reviewed and cross-referenced as the foundation for detailed analysis. A number of site interviews were held with key personnel within Ergon Energy. Details of the site visits (for this and later stages) are contained in Appendix 10.1 and a list of key documents accessed (during this and later stages) is contained in Appendix 10.2.

2.2.2 "Desk Study" Review

This stage involved the detailed review of the information gained in Stage one. Factors considered included the following:

- The information contained in the QCA Draft Determination;
- The outworkings of the EDSD Review;
- Changes to operating, maintenance, augmentation and replacement strategies;
- Changes to planning processes;
- Network capacity and utilisation;
- Regulatory, safety and environmental compliance issues;
- Organisational changes;
- Changes to performance standards;
- Resourcing capability; and
- Assumptions underpinning Ergon Energy's forecasts of CAPEX and OPEX.

Outcomes from this stage were the identification of key issues and the identification of areas requiring further information. BRW has also drawn on its experience with other Distribution Network Service Provider ("DNSPs"), but has not directly used information provided to it on a commercial-in-confidence basis.

2.2.3 Review of Significant Issues

Significant issues identified in the earlier stages of the review were discussed with relevant managers within Ergon Energy to ensure that BRW correctly understood the issues and to gain further insights into the business.

2.2.4 Preparation of Draft Report

The findings, analysis and conclusions arising from the four preceding stages were collated and integrated into the draft report.

2.2.5 Preparation of Final Report

Comments received and issues raised from the Draft Report have been considered and used as input into the preparation of this Final Report.

3 DRAFT DETERMINATION

In its Draft Determination, Regulation of Electricity Distribution, December 2004, the QCA made the following allowances for expenditure for Ergon Energy:

Table 3-1: Draft Determination CAPEX (inc. overheads)

	2005/06	2006/07	2007/08	2008/09	2009/10	TOTAL
Asset Replacement	136.0	130.4	131.6	128.3	129.1	655.4
Demand Related						
Augmentations	105.3	104.7	110.6	100.7	83.7	505.2
Customer Initiated	112.7	114.0	114.4	118.2	121.5	580.8
Reliability Improvement	1.5	1.6	1.5	1.6	1.6	7.8
Other System	8.6	9.8	9.5	9.3	8.7	45.9
Non-System	75.8	64.7	66.3	66.9	61.4	335.1
Tier (b) Expenditure*	5.7	5.7	5.7	5.7	5.7	28.4
Tier (c) Expenditure*	22.7	28.4	23.4	46.9	16.8	138.5
Total CAPEX	**468.4**	**459.3**	**463.2**	**477.6**	**428.5**	**2,296.9****

All forecast figures are in June 2004 dollars (millions).
** Refer to BRW submission to QCA on Ergon Energy (December 2004) Section 5.6.3 pg. 36 for definition.*
*** Excludes $173.4 million for large, but uncertain, projects set aside for future inclusion.*

Table 3-2: Draft Determination OPEX (incl. overheads)

	2005/06	2006/07	2007/08	2008/09	2009/10	TOTAL
Lines	91.9	93.1	92.9	77.5	78.8	434.2
Vegetation	48.6	48.9	48.6	55.2	55.7	256.0
Substations	22.4	22.7	22.8	23.6	24.2	115.7
Meters	2.9	3.5	3.5	3.9	4.5	18.20
Total Maintenance	**165.8**	**168.2**	**167.8**	**160.2**	**163.1**	**825.10**
Network Operations	11.8	11.9	11.8	12.1	12.3	59.9
Customer Service	31.9	32.7	33.1	34.5	35.7	167.9
Total Operations	**43.7**	**44.6**	**44.9**	**46.6**	**48.0**	**227.8**
Total OPEX	**209.6**	**212.8**	**212.7**	**206.80**	**211.01**	**1,052.9**

All forecast figures are in June 2004 dollars (millions).

The Draft Determination contained a number of key elements that are relevant in the consideration of the required levels of CAPEX and OPEX, as follows:

3.1 Demand Triggers

Each distributor's fixed revenue cap is established on the basis of an asset base and CAPEX and OPEX forecasts that reflect assumptions about the future demand on the network. Under a fixed revenue cap, a distributor's annual revenue required remains the same regardless of the extent to which actual demand varies from the forecast. This is because any under or over recovery of revenue in a particular year will be recovered form/returned to customers through higher or lower prices in subsequent years.

While a distributor's revenue does not vary with divergences between forecast and actual demand, its capital and operating costs may. In order to increase investment certainty for Energex and Ergon Energy, by mitigating the cost risks associated with deviations in actual demand from that forecast, the EDSD Review recommended that the QCA consider alternative arrangements including, but not limited to, a flexible revenue cap based on variable demand levels.

The QCA proposes to apply triggers to the key network cost drivers of customer numbers (3 per cent variance) and maximum demand (5 per cent variance) for both Energex and Ergon Energy in the next regulatory period.

3.2 Cost Pass-Through Events

The QCA proposes to introduce a materiality threshold for consideration of cost pass-through of 1 percent of actual annual revenue per event, based on the regulated revenue in the year of the event. This would require a single event to have unforeseen costs of around $5M before being considered by the QCA for potential pass-through of these costs.

3.3 Pass-Through Mechanism for Major Customer Works

The QCA proposes to introduce a pass-through mechanism for Ergon Energy to accommodate identified capital projects totalling $173.4M that are likely to proceed during the next regulatory period, but where the probability of proceeding is less than 80 per cent. Each project will also have to have a potential cost of at least $5M. The Authority also proposes to consider pass-through for large customer projects, with a cost in excess of $30M, that occur during the next regulatory period but were totally unanticipated.

3.4 Service Quality Incentive Scheme

The QCA does not propose to proceed with implementing its service quality incentive scheme at this time. The QCA will consider implementing the scheme once performance levels have improved and stabilised at a level consistent with broad community expectations.

4 ELECTRICITY DISTRIBUTION & SERVICE DELIVERY REVIEW

An Independent Panel ("Panel") was established by the Queensland Government in March 2004 to undertake the EDSD Review. The Panel was required to examine certain matters relating to the electricity distribution services provided by Ergon Energy and Energex, including an assessment of reliability and levels of capital and operating expenditure and whether those factors together with existing or proposed internal systems will ensure reliable networks for the 21st century.

The Panel made 44 recommendations in July 2004, and the Queensland Government has made a commitment that all of the recommendations will be implemented. The EDSD Review recommendations cover the areas of reliability performance, customer service standards, network capacity, communications, workforce capability and the regulatory environment.

Key recommendations include the following:

- Introduction of minimum service standards;
- Introduction of GSL rebates;
- Targeted improvement to worst performing areas of the network;
- Investigation of options to improve performance of the SWER system;
- Reduction in load and voltage constraints;
- Improved maintenance programs, particularly in areas of preventative maintenance and vegetation management;
- Improvements to the asset management systems;
- Adoption of more conservative planning criteria and improved network planning;
- Increased system planning resources for Energex;
- Improved Contact Centre performance;
- Improved communications to the public regarding outages;
- Increased numbers of apprentices; and
- Improved performance monitoring and reporting.

Ergon Energy has committed to implementing all of the recommendations that apply to Ergon Energy. This will involve some additional network investment, in both OPEX and CAPEX.

As an outworking of the EDSD Review, the Government has introduced the Electricity Industry Code, effective from 1st January 2005. The Code requires each distributor to:

- Prepare and publish an annual summer preparedness plan;
- Prepare and publish an annual network management plan;
- Use its best endeavours to meet set minimum service standards;
- Pay GSL rebates to customers where specific service levels are not achieved; and
- Monitor and report its performance against minimum service standards and GSLs, and audit its performance against minimum service standards.

5 OPEX

With the exception of vegetation management improvements, GSL payments, insurance and reporting, the required programmes under the EDSD recommendations, involving operating expenditure, have already been initiated and the expenditure has been covered by the previous submission with no additional cost.

EDSD related programmes which are already in place include:

- An aggressive plan to improve inspection and maintenance of the network, including protection equipment, to improve reliability;
- The updating of maintenance and asset management systems and integration with the GIS system is proceeding to program;
- Mincom Ellipse is due to replace SAP in 2006, but this transition has already been factored into plans;
- Customer communication programs during unplanned outages are in place; and
- A resource and training strategy to provide for future operating and asset maintenance plans.

The changes in forecast OPEX contained in Ergon Energy's revised submission are summarised in Table 5-1 and discussed in detail in the following sections.

Table 5-1: Changes in OPEX Budget Compared to Draft Determination (incl. overheads)

AREA	DRAFT DETERMATION	REVISED ERGON ENERGY FORECAST (2005)	REVISED BRW FORECAST (2005)	COMMENT
Lines	434.2	434.2	434.2	No change.
Vegetation	257	342.4	338.3	Section 5.1
Substations	115.7	115.7	115.7	No change.
Meters	18.2	18.2	18.2	No change.
Network Operations	59.9	59.9	59.9	No change.
Customer Service	167.9	167.9	167.9	No change.
GSL Payments	0	2.2	0	Section 5.2
Self-Insured Costs	0	16.7	16.7	Section 5.3
Reporting	0	0.5	0.5	Section 5.4
EBA OPEX Impacts	0	122.8	101.64	Section 5.5
TOTAL	**1,052.9**	**1,280.5**	**1,253.2**	

All costs are in millions of June 2004 dollars, totalled for the 5-year period

5.1 Vegetation

Subsequent to the release of the Draft Determination in December 2004, Ergon Energy has developed a revised Vegetation Management OPEX forecast. The revised forecast indicates a significant increase of $85.4M including overheads, 33.2% over the regulatory period compared to the original Ergon Energy 2004 submission, as shown in Table 5-2.

The increase has been driven by the need to deal with a growing backlog of vegetation works, improvement notices issued by the Electrical Safety Office and recommendations made in the EDSD report.

Table 5-2: Vegetation Management Operation Budget (incl. overheads)

	05/06	06/07	07/08	08/09	09/10	TOTAL
2004 Draft Determination	48.56	48.87	48.62	55.21	55.72	256.98
Revised Ergon Energy Forecast (2005)	78.61	74.33	72.71	59.47	57.30	342.42
Revised BRW Forecast (2005)	78.61	74.33	72.71	57.38	55.31	338.34

All forecast figures are in June 2004 dollars (millions)

In the second half of 2004, Ergon Energy completed a comprehensive review of it's current vegetation practices and policies.

These are designed to improve reliability, public safety and reduce operational costs in the longer term by increasing the scoping activity and reduced cycle periods for clearing in all regions. This will have greatest effect in the Central and Southern regions. Specific changes which have been incorporated into the revised vegetation policy include:

- Bushfire mitigation measures in specified areas west of the divide and in the central and southern areas;
- Obtaining improved records of vegetation for more efficient control and planning;
- A three year policy of clearing with a view to longer cycles in the future. This includes:
    - Annual scoping and clearing of all vegetation and more extensive trimming in urban areas;
    - More extensive clearing of all rural areas, with the three year cycle being adopted. This may be compared back to the previous five year cycle.
- Removal of problem trees and stem injection;
- More efficient access track maintenance policy; and
- Development of Summer Preparedness Plans in response to the Government requirements detailed in the EDSD report.

The review also revealed a growing backlog of vegetation work and consequently increased risks to the network operations. It is likely that the lack of available historical data and network knowledge (a legacy of the work practices of the six DNSPs in operation prior to the formation of Ergon Energy) is the primary cause of the vegetation backlog. The Central and Southern regions, in particular, have very limited historical data associated with rural vegetation clearing, as there has been a policy to focus on urban vegetation clearing without the systematic approach used in the Northern region.

The backlog is evident from an analysis of historical spending and planned spending in the various regions.

In the rural areas of Southern and Central regions this has been approximately $4.1M per year during 2002/03 and 2003/04, and in the first 3 years of the regulatory period it is planned to spend $12.5M per year. Also, it was found that inspection cycles were 19 years. These will now be addressed with a 3 year cycle with the aim of increasing this to 5 years in the long term.

In the urban areas of the Southern and Central regions the spending has been approximately $3.1M per year and the increase in the first 3 years of the regulatory period it is planned to be $12.4M per year

During the review of vegetation practices, a comprehensive system of unit rates for scoping of clearing and track maintenance, actual clearing, customer initiated clearing, forced clearing, minor and major track maintenance and gate repair in different areas of the network was developed. This was only available in a moderately developed format at the time of the 2004 submission.

In this submission they have been developed from historical costs since 2002/03.

Unit rates for each of the regions over the period are shown below:

Table 5-3: Unit rates for Vegetation Management

	Urban Cost per Span	Rural Cost per Span
Northern Region	$61	$117
Central Region	$79	$143
Southern Region	$32	$171

All figures are in June 2004 dollars

These rates again indicate the effort to improve the situation in the Central and Southern rural regions.

Similar figures have been developed for areas in urban locations and individual feeders to indicate the types of vegetation to be managed.

This will, after further experience and recording of actual costs, be refined to produce more accurate unit rates for control and forecasting of vegetation costs and are expected to show improvement after the 3 year cycle.

5.1.1 Conclusions

The significant increase is because of the additional policies and requirements that have been identified, including the strategy to improve public safety and reduce operational costs in the longer term.

The establishment of a refined system of unit rates for vegetation management in specific areas of the network is a very positive strategy.

Vegetation has been found to have less than 10% impact on supply interruptions, and therefore has only a small impact on reliability. Nevertheless, BRW is of the opinion that the revised vegetation policies will give Ergon Energy greater control over vegetation issues and enable them to move towards a preventative rather than reactive vegetation approach in the future and will meet regulatory requirements and improve public safety.

It is recognised that Ergon Energy has derived the unit rates for vegetation work from minimal historical data and these may reflect the inefficient work practices used in the past. Nevertheless, the forecasts are considered reasonable for the first three years of the regulatory period. It is expected that as the extent and types of vegetation and associated clearing costs are recorded, sufficient information will be obtained to better control and minimise costs in the future. This should result in reduced costs towards the end of the regulatory period. BRW has accounted for this effect by introducing progressive reductions in levels of Urban and Rural Forced Maintenance as well as reduced unit rates for Urban and Rural Clearing and Removal in the final two years of the regulatory period. These changes result in a reduction of $4.08M over the regulatory period compared to Ergon Energy's revised forecast as shown in Table 5-2.

5.2 GSL Payments

Following the recommendation from the EDSD report and with the introduction of the Electricity Industry Code in December 2004, GSLs have been introduced and will be fully effective from 1st July 2005. GSL rebates are available to non-contestable customers where specific customer service standards have not been achieved.

Ergon Energy has had a number of GSLs with rebates in operation for some time but with the introduction of the Electricity Industry Code and the publicity throughout the community the impact is expected to provide the DSNPs with further incentive to improve performance.

The GSLs and associated rebates are as follows:

- Wrongful disconnection - $100;
- Failure to connect - $40 for each late day;
- Customer reconnection - $40 for each late day;
- Attention to loss of hot water supply - $40 for each late day;
- Failure to keep appointments - $40;
- Failure to give 2 days notice of planned interruptions - $20 or $50; and
- Customers experiencing more than a specified number of interruptions or interruptions longer than a specified duration - $80.

Ergon Energy has included in its submission an amount of $2.2M for the regulatory period as shown in Table 5-4.

Table 5-4: GSL Payments Budget (incl. overheads)

	05/06	06/07	07/08	08/09	09/10	TOTAL
Revised Ergon Energy Forecast (2005)	0.43	0.42	0.42	0.44	0.45	2.15
Revised BRW Forecast (2005)	0	0	0	0	0	0

All forecast figures are in June 2004 dollars (millions)

5.2.1 Conclusion

It is BRW's view that to provide incentive to ensure expenditure is focussed on delivering both service reliability and financial outcomes, this should not be included. Instead, provision of the amount removes the incentive to improve customer service and rebates should be paid from business profits.

5.3 Self-Insured Costs

Ergon Energy has been given the opportunity of submitting a proposal to use self insurance to account for risks which present a real possibility of significant material loss during the regulatory period.

The forecast self insurance costs, detailed in Table 5-5, are based on work done by SAHA International Limited who conducted a high level desktop review and estimation of the risks faced by Ergon Energy's distribution business. BRW has no firsthand knowledge of SAHA International. However it is understood to be a reputable economic and financial consulting group specialising in utilities and infrastructure. Previous clients have included PowerLink Queensland, Integral Energy and TransPower.

BRW does not consider itself qualified to assess the financial aspects of insurance risk and therefore recommends that QCA seeks the opinion of a suitably qualified independent insurance advisor.

Table 5-5: Self Insurance Costs Budget (incl. overheads)

	05/06	06/07	07/08	08/09	09/10	TOTAL
Revised Ergon Energy Forecast (2005)	3.30	3.24	3.26	3.40	3.51	16.70

All forecast figures are in June 2004 dollars (millions)

5.4 Reporting

Ergon Energy has included an additional $0.54M over the regulatory period (as shown in Table 5-6), in their submission on the basis that there is an extra requirement for reporting. This is a requirement of the Electricity Industry Code and includes monthly reporting to the government on reliability, service quality, contact centre performance, network capacity, capital and operating expenditure progress and vegetation management.

In addition, a Network Management plan has been produced as an interim document with a final document due in August 2005. This document is a detailed consolidation of service performance and policies and plans in all aspects of the networks operations.

It is BRW's opinion that this cost is justifiable as an essential part of managing the network and informing government and the community of the state of the business.

Table 5-6: Reporting Budget (incl. overheads)

	05/06	06/07	07/08	08/09	09/10	TOTAL
Revised Ergon Energy Forecast (2005)	0.11	0.10	0.11	0.11	0.11	0.54

All forecast figures are in June 2004 dollars (millions)

5.5 EBA Impacts

Ergon Energy has revised the expected outcomes of the forthcoming 2005 EBA agreement in light of the recommendations made in the EDSD report. As a result, the OPEX forecast has increased by $117.56M (incl. overheads) across the regulatory period as shown in Table 5-7.

BRW has revised the OPEX forecast as discussed further in Section 7. The impact of the EBA on Ergon Energy and BRW's revised OPEX forecasts are shown in Table 10-1.

Table 5-7: EBA Operation Budget (incl. overheads)

	05/06	06/07	07/08	08/09	09/10	TOTAL
Revised Ergon Energy Forecast (2005)	17.04	24.08	25.75	27.26	28.64	122.77
Revised BRW Forecast (2005)	14.70	21.17	21.96	21.93	21.89	101.64

All forecast figures are in June 2004 dollars (millions)

5.6 Separate Accounts

Ergon Energy has been advised that to conform to regulatory requirements, accounts are to be submitted to the QCA using labour only as the basis for overheads.

The existing statutory accounts system used by Ergon Energy allocates overheads based on labour and materials. The decision to proceed in this way was as a result of a review of other regulatory businesses using this system during the formation of Ergon Energy.

Ergon Energy proposes to maintain the existing statutory ledger system as it is believed to more accurately reflect the application of overheads than the regulatory ledger system. Therefore, the regulatory ledger would need to be maintained in parallel to the existing statutory ledger.

Ergon Energy is in the process of migrating its financial systems to Mincom Ellipse (expected completion in July 2006). This software package has been designed to accommodate two parallel ledgers, these being the statutory and taxation ledgers. In order to introduce the additional regulatory ledger, a major reconfiguration of the Mincom Ellipse system structure would be required.

A major change to the accounting software with additional resources would be required to manage the additional reporting and system requirements.

Based on subsequent information, QCA and Ergon Energy have agreed upon a higher level reconciliation reporting system, with overheads based on labour only, without the introduction of a parallel ledger. Ergon Energy has indicated that this can be achieved without additional costs. Therefore, the costs associated with the preparation of regulatory accounts (i.e. $5.0M over the five year regulatory period) have been omitted from Ergon Energy's submission in this report.

BRW suggests that in the long term the QCA give consideration to adopting a single accounting treatment of overheads.

5.7 Revised OPEX Forecast

A summary comparison between Ergon Energy's revised submission and BRW's OPEX forecast is shown in Table 5-8. It is noted that the EDSD EBA impacts and EDSD Reporting Requirements have been distributed across the relevant OPEX categories on a pro-rata basis. A detailed comparison between Ergon Energy's revised submission and BRW's OPEX forecast is shown in Section 10.3.

Table 5-8: Draft Determination and Revised OPEX (incl. overheads)

	05/06	06/07	07/08	08/09	09/10	TOTAL
DRAFT DETERMINATION						
Maintenance	163.83	168.22	167.79	160.18	163.09	825.11
Operations	43.75	44.58	44.92	46.62	47.97	227.84
Total OPEX	**209.58**	**212.80**	**212.71**	**206.80**	**211.06**	**1,052.95**
REVISED ERGON ENERGY FORECAST (2005)						
Maintenance	212.59	216.18	215.77	189.65	191.09	1025.28
Operations	47.80	49.82	50.46	52.51	54.15	254.74
Total OPEX	**260.39**	**266.00**	**266.23**	**242.16**	**245.24**	**1280.02**
REVISED BRW FORECAST (2005)						
Maintenance	210.65	213.77	212.64	183.14	183.52	1003.72
Operations	47.08	49.00	49.49	51.27	52.64	249.48
Total OPEX	**257.73**	**262.78**	**262.13**	**234.41**	**236.16**	**1253.20**

All forecast figures are in June 2004 dollars (millions)

6 CAPEX

6.1 Summary of Changes

The changes in forecast CAPEX contained in Ergon Energy's revised submission are summarised in the following table:

Table 6-1: Draft Determination and Revised CAPEX

AREA	DRAFT DETERMINATION	REVISED SUBMISSION	DIFF.	REVISED SUBMISSION (inc allocation of SWER, EBA and Market Rates)	DIFF.
Asset Replacement	655.4	655.4	0.0	686.1	30.8
Augmentation	505.2	700.9	195.7	778.6	273.4
Customer Initiated	580.8	683.6	102.8	702.3	121.5
Reliability	174.5	205.4	30.9	235.1	60.6
Other System	45.9	45.9	0.0	58.5	12.6
Non-System	335.1	355.1	20.0	355.1	20.0
SWER	0	58.7	58.7	-	-
EBA CAPEX Impacts	0	61.7	61.7	-	-
Market Rates	0	49.0	49.0	-	-
TOTAL	**2,296.9**	**2,815.7**	**518.7**	**2,815.7**	**518.7**

All costs are in millions of June 2004 dollars, totalled for the 5-year period

Of the total increase of $518.7M sought by Ergon Energy, $285.3M is directly attributable to the EDSD report, as shown in the following table:

Table 6-2: Sources of Increases from Draft Determination

	DRAFT DETERMINATION	EDSD INCREASE	OTHER INCREASE	TOTAL INCREASE	REVISED TOTAL
Asset replacements	655.4	5.0	25.8	30.8	686.1
Augmentation	505.2	212.9	60.5	273.4	778.6
Customer Initiated	580.8	0.0	121.5	121.5	702.3
Reliability	174.5	56.4	4.1	60.6	235.1
Other System	45.9	10.9	1.6	12.6	58.5
Non-System	335.1	0.0	20.0	20.0	355.1
Total CAPEX	**2,296.9**	**285.3**	**233.4**	**518.7**	**2,815.7**

All costs are in millions of June 2004 dollars, totalled for the 5-year period to June 2010

6.2 Augmentation

6.2.1 Process to Develop Revised Expenditure Forecasts

Ergon Energy's revised forecasts for augmentation expenditure are based on the most recent (2004) Sub-transmission Network Augmentation Plans ("SNAPS") and Distribution Capability Reviews (the process for development of Ergon Energy's capital expenditure forecasts is described in Section 9.2.1 of BRW's Final Report 21st December 2004).

In developing the revised SNAPS and Distribution Capability Reviews, Ergon Energy has taken into account the following factors:

- Revised planning criteria as a result of EDSD ("N-1", removal of load constraints etc, as discussed in Ergon Energy's Network Management Plan 2004 - 2010);
- Addressing replacement of LV copper conductor as required by EDSD;
- 2004 demand forecasts (updated from 2003);
- Updated Powerlink planning requirements; and
- Recalculation of system studies with current data – improvements have been made since the previous SNAPS were done, including more accurate plant ratings (some de-rating of plant has occurred, particularly underground cables) and improved metering information.

Ergon Energy compared the 2004 SNAPS and Distribution Capability Reviews against those developed in 2003 and noted the differences. They also identified the reason for the changes to allow the allocation of the expenditure to the categories listed in the following section.

6.2.2 Revised Submission

In its revised submission, Ergon Energy has requested an additional $195.7M for augmentation works, as shown in the following table:

Table 6-3: Revised CAPEX Submission

	05/06	**06/07**	**07/08**	**08/09**	**09/10**	**TOTAL**
Draft Determination	105.3	104.7	110.6	100.7	83.7	505.2
Additional Requested	11.1	76.4	64.1	20.9	23.2	195.7
Revised Total	**116.4**	**181.2**	**174.8**	**121.7**	**106.9**	**700.9**

All forecast figures are in June 2004 dollars. (millions)

6.2.3 Summary of Changes

In its revised submission, Ergon Energy has broken the additional expenditure into the following categories:

Table 6-4: Summary of CAPEX changes

AREA	$M	COMMENT
EDSD REQUIREMENTS	**109.7**	
Sub-transmission system security criteria as a result of EDSD	29.8	New projects identified in 2004 SNAPS directly caused by revised planning criteria
Reduction of distribution system load & voltage constraints as required by EDSD	21.0	Reduction of HV feeder constraints to 15% of total feeders
Use of PoE 10 as required by EDSD	47.0	Effect is to bring forward about 1 year's growth
Addressing replacement of LV copper conductor as required by EDSD	11.9	Required to allow proactive monitoring of LV voltage issues
REVISED DEMAND FORECASTS	**15.3**	
Updated maximum demand forecasts	15.3	New projects identified in 2004 SNAPS directly caused by higher demand forecasts in 2004
ADDITIONAL WORK	**70.7**	
Net additional work identified in updated SNAPS	41.0	New projects identified in 2004 SNAPS
Additional cost for revised scope of works for projects (revised scope identified by 2004 SNAPS)	27.7	Projects in 2003 SNAPS requiring revised scope in 2004 SNAPS
Additional cost for works required by Powerlink based on their updated plans	2.0	Additional works required to connect Powerlink changes
TOTAL	**195.7**	

All costs are in millions of June 2004 dollars, totalled for the 5-year period to June 2010

In comparing the cost of individual sub-transmission and distribution projects contained in the 2003 and 2004 SNAPS and Distribution Capability Reviews, BRW identified that many projects had significantly increased in cost from 2003 to 2004. In reviewing the reasons for the cost increases, the following two factors were identified:

- Increased scope of works; and
- An increase in unit rates.

The increased scope of works has arisen from a more detailed understanding of the projects (moving from a concept design to a more detailed design). BRW is satisfied that the increased scope of works for individual projects has been appropriately identified.

For augmentation works, Ergon Energy had applied its own unit rates but was directed by the QCA to apply the SKM unit rates. Estimates for categories of work other than augmentation were derived by other means and the unit rates issue does not apply.

6.2.4 EDSD Requirements

Revised Sub-transmission Planning Criteria ($29.8M)

In its revised submission, Ergon Energy states that:

> *"Ergon Energy is implementing the recommendation of the EDSD Report that N-1 security levels be maintained at all bulk supply substations and major/critical zone substations and sub-transmission feeders such that supply is maintained following the loss of a single system element. This is a higher standard of security than that previously applied, which had allowed for loads to exceed the N-1 capability for up to 1% of the time.*
>
> *Implementation of the N-1 security level recommendation referred to above has necessitated a detailed review of the network planning targets with respect to security criteria. These new planning criteria are fully described in the Network Management Plan.*
>
> *The Subtransmission Network Augmentation Plans for 2004 were completed using the new planning criteria."*

Ergon Energy has applied the revised planning standards as required by the EDSD Report in developing its detailed plans for sub-transmission works. BRW has reviewed the list of projects in this category and is satisfied as to the rigour of the process used to identify the proposed works. BRW considers the costs to be reasonable.

Revised Distribution System Planning Criteria ($21.0M)

In line with Recommendation 15 of the EDSD Report, Ergon Energy plans to significantly reduce the number of HV feeders with load and capacity constraints over the regulatory period, at a cost of $23.8M (excluding SWER feeders which are dealt with separately). The current and projected status is shown in the following table:

Table 6-5: Current and projected status of HV feeder constraints

	CURRENT STATUS (2003/04)		PROJECTED STATUS (2009/10)	
CATEGORY	**NUMBER**	**%**	**NUMBER**	**%**
Total Feeders	1739	100	1913	100
Capacity Constraints	468	27	196	10
Voltage Constraints	242	14	150	8
Total Constraints	**591***	**34**	**292***	**15**

** Note: Some feeders have both capacity and voltage constraints*

BRW has reviewed the list of projects in this category and is satisfied as to the rigour of the process used to identify the proposed works. BRW considers the costs to be reasonable.

Use of PoE 10 ($47.M)

The EDSD Report recommended that Ergon Energy consider adopting the application of a Probability of Exceedence of 10% (PoE 10) forecasting assumption. Ergon Energy has made allowance of $47M in its CAPEX forecasts for the application of the PoE 10 assumption for Bulk Supply Substations and Zone Substations with a load in excess of 15MVA. Ergon Energy contend that the impact of this is to bring forward approximately 1 year's growth, which is consistent with BRW's experience. This would equate to an additional 70MW of MD.

In its Final Report dated 21 December 2004, BRW derived a rate for Ergon Energy of around $0.7M per additional MW of MD, which would result in an additional $49M being required for the adoption of the PoE 10 forecasting assumption. BRW considers Ergon Energy's estimates to be of the right order but has reduced them to $41.4M in line with the SKM Unit Rates.

Replacement of LV 7/064 Copper Conductor ($11.9M)

In line with Recommendation 16 of the EDSD Report, Ergon Energy plans to replace small LV copper conductors over the forthcoming regulatory period, at an estimated cost of $11.9M. This represents a change from the previous reactive approach to a proactive identification and rectification of problem areas. Due to inadequacies in the current level of reliable data regarding LV conductor sizes and types, the amount of small LV copper conductors requiring replacement, and therefore the cost, is not accurately known at this time. The estimated level of expenditure was based on the assessment of the level of work that would practicably be able to be identified and completed.

Although it is not possible to quantify the required work (for example, on the basis of known kilometres of conductor requiring replacement multiplied by a cost per kilometre), BRW is of the view that the $11.9M requested would achieve the replacement of only part of the small-sized copper LV conductors. It can be anticipated that by the time of the next regulatory price review Ergon Energy will have a more detailed knowledge of its LV network and will be able to make a more detailed assessment of the remaining work required. On this basis, BRW considers the work proposed for this program and the costs to be reasonable.

6.2.5 Revised Demand Forecasts ($15.3M)

Ergon Energy based its original submission on a forecast growth in MD of 3.3% over the period, compared with the forecast made by McLennan Magasanik Associates Pty Ltd ("MMA") of 3.6% growth (refer Table 6, Page vii of the MMA report). In its Final Report, BRW estimated the difference in MD forecasts between Ergon Energy and MMA to equate to a cost of $31M in corporate initiated works.

Ergon Energy has revised its MD forecasts to an average of 4% over the forthcoming regulatory period. To cater for the higher MD, Ergon Energy has developed its revised CAPEX forecasts by considering the specific projects required to meet the increased MD i.e. a "bottoms up" approach. The forecast of MD is driven by two elements:

Regression Analysis

Every new data point influences the next forecast according to the extent to which the new data point differs from the previously forecast value. A higher peak than that forecast will tend to increase the slope of the new projection over that forecast. Ergon Energy's previous forecast was produced in late 2003, prior to the 2004/04 peak. The actual demand was 95MW higher than that forecast (42MW temperature corrected).

Economic Factors

Economic factors considered include indicators of activity levels plus known step load increases. In the 12 months up to late 2004 when the most recent forecast was produced, there have been indicators that projected load growth in the mining and industrial sectors will be higher than previously anticipated, as the enquiry rates from proposed new establishments and for expansion at existing sites has increased, in response to changing market conditions, particularly in the coal sector. The sum of the specified step load increases identified and included in the 2003 forecast for the period 2005/06 to 2009/10 was 784 MW, compared with the step load increase in the latest forecast for the same period is 1083 MW, an increase of 299 MW.

Conclusion

BRW is not in a position to assess the appropriateness or otherwise of Ergon Energy's projected increase in maximum demand from 3.3% to 4.0%. BRW considers that the increased expenditure requested is broadly consistent with the increased growth rate (in fact, using the high level approach discussed in its initial report, BRW would expect even more expenditure would be required, although it is recognised that the more detailed assessment made by Ergon Energy would yield a more accurate forecast). Assuming that the growth in MD is the 4% forecast by Ergon Energy, BRW accepts the level of work required and considers the costs to be reasonable.

6.2.6 Additional Work ($70.7M)

Ergon Energy has identified a number of additional projects that can not be attributed to revised planning criteria or the higher demand forecasts. BRW notes Ergon Energy's comments that it has not been easy to clearly identify the appropriate classification (e.g. whether the main driver for a project is the revised demand forecasts or as a result of a strategic plan) for new projects in the 2004 SNAPs. BRW does not see this as an issue, as it does not affect the need for the projects, but merely which category they might be assigned.

BRW has compared the list of projects contained in the 2003 SNAPs with those in the 2004 SNAPs and has reviewed the reasons for significant cost differences at the individual project level. BRW is satisfied that Ergon Energy has followed a rigorous process to identify the need for new augmentation projects and changes in scope for existing projects.

The $70.7M is made up of the following items:

New Work Identified in Updated SNAPs ($41.0M)

Since making its initial submission, Ergon Energy has completed a number of long-term strategic plans, particularly one covering the Wide Bay area, and these have been reflected in the 2004 SNAPs. The strategic plans provide a framework for planning the development of the network and have identified the need for works in the medium term. Projects include the installation of additional capacitor banks, upgrading of underground cable exits, upgrading of switchgear and the purchase of substation sites and line routes for future projects in the following regulatory period.

BRW has reviewed the list of projects in this category and supports the need for the projects. BRW considers the costs to be reasonable.

Increased Scope of Works ($27.74M)

As identified in Section 6.2.3, the scope has been revised for a number of projects (generally arising from the adoption of alternative options for the project), resulting in increased project costs for those projects. The alternative options include such situations as:

- Undergrounding all of a new HV line in lieu of partial undergrounding;
- Line changed from single to dual circuit;
- Purchase of a new transformer rather than use of an existing transformer;
- Installation of two transformers initially instead of a staged development; and
- Inclusion of 66kV bus-tie CB & associated protection.

BRW has reviewed the list of projects in this category and the reasons for the increases, and supports the need for the increased scopes. BRW considers the costs to be reasonable.

Updated Powerlink Plans ($2.0M)

Powerlink have revised their plans, resulting in work for Ergon Energy to connect to Powerlink assets. BRW has reviewed the work in this category and supports the need for the work. BRW considers the costs to be reasonable.

6.2.7 Summary

A comparison between Ergon Energy's and BRW's Augmentation forecasts are shown in the following table:

Table 6-6: Summary Comparison of Ergon Energy and BRW Augmentation Forecasts

AREA	Ergon Energy	BRW
EDSD REQUIREMENTS	**109.7**	**104.1**
Sub-transmission system security criteria as a result of EDSD	29.8	29.8
Reduction of distribution system load & voltage constraints as required by EDSD	21.0	21.0
Use of PoE 10 as required by EDSD	47.0	41.4
Addressing replacement of LV copper conductor as required by EDSD	11.9	11.9
REVISED DEMAND FORECASTS	**15.3**	**15.3**
Updated maximum demand forecasts	15.3	15.3
ADDITIONAL WORK	**70.7**	**70.7**
Net additional work identified in updated SNAPS	41.0	41.0
Additional cost for revised scope of works for projects	27.7	27.7
Additional cost for works required by Powerlink based on their updated plans	2.0	2.0
TOTAL	**195.7**	**190.0**

All costs are in millions of June 2004 dollars, totalled for the 5-year period to June 2010

6.3 Reliability

6.3.1 Draft Determination

The Draft Determination provided the following levels of expenditure for reliability CAPEX:

Table 6-7: Draft determination reliability CAPEX

	2005/06	2006/07	2007/08	2008/09	2009/10	TOTAL
Reliability Improvement	1.5	1.6	1.5	1.6	1.6	7.8
Tier (b) Expenditure	5.7	5.7	5.7	5.7	5.7	28.4
Tier (c) Expenditure	22.7	28.4	23.4	46.9	16.8	138.2
Total Reliability	**29.9**	**35.7**	**30.6**	**54.2**	**24.1**	**174.5**

All forecast figures are in June 2004 dollars. (millions)

Tiers (a), (b) and (c) are defined in BRW submission to QCA on Ergon Energy (December 2004) Section 5.6.3 pg. 36.

Ergon Energy, in its original submission, requested expenditure of $146.3M over the period for Tier (c) which included the expenditure for Tiers (a) and (b) (as noted on Page 114 of BRW's Final Report). The Draft Determination provided $174.5M, thus giving Ergon Energy an additional expenditure of $28.2M.

6.3.2 Revised Submission

The Electricity Industry Code establishes minimum service standards ("MSSs") in regard to SAIDI and SAIFI, that apply in Ergon Energy's case to Urban, Short Rural and Long Rural feeders, with quantified targets set for each year for each category of feeder. These targets exclude major event days, calculated by the Beta Method as detailed in Schedule 1 of the Code. As the introduction of MSSs was a recommendation of the EDSD report, the additional expenditure associated with achieving the standards can be attributed to the EDSD report.

Since the original submission was made, Ergon Energy has conducted a more detailed analysis of the reliability projects. This analysis by Ergon Energy shows that Tier (c) expenditure will allow it to meet the MSS for Long Rural feeders, but that additional expenditure is required by Ergon Energy in excess of that put forward as Tier (c) expenditure, in order for Ergon Energy to achieve the MSSs for Urban and Short Rural feeders. The gaps in SAIDI have been identified by Ergon Energy as 12 and 41 customer minutes for Urban and Short Rural feeders respectively. Ergon Energy has not identified individual projects to develop its forecasts of the additional expenditure required, but instead has derived a cost (from experience with the current reliability program) to achieve an improvement of one SAIDI customer minute for both Urban and Short Rural feeders. This is summarised in the following table:

Table 6-8: Relationship between feeder type, SAIDI and CAPEX

FEEDER TYPE	SAIDI	CUSTOMER MINS	$/CUSTOMER MINS	$M
Urban	12	2,789,593	2.07	5.769
Short Rural	41	10,658,375	5.61	59.836
Total				**65.606**

All forecast figures are in June 2004 dollars. (millions)

The costs quoted here are with overhead allocations on the basis of labour and materials; for overheads allocated on labour only, the cost reduces from $65.6M to $51.7M.

BRW considers that the approach used by Ergon Energy, to estimate the required expenditure, is appropriate, as it is not practicable to identify individual projects (many of them will be small) at this point. Based on its experience, BRW considers the cost per customer minute derived by Ergon Energy to be reasonable.

In its revised submission, Ergon Energy requested an additional amount of $30.9M, derived as follows:

Table 6-9: Ergon Energy Reliability CAPEX

	(Labour Only Overheads)
Revised Ergon Energy submission	153.7
MSS Gap	51.7
Total Required	**205.4**
Allowed in Draft Determination	174.5
EDSD Increment Over Draft Determination	30.9

All forecast figures are in June 2004 dollars. (millions)

Ergon Energy has erroneously quoted an amount of $153.7M for Tier (c) expenditure; it should have been $146.4M (this has been confirmed with Ergon Energy). Accordingly, BRW has reduced the EDSD increment to $23.5M as follows:

Table 6-10: BRW Reliability CAPEX

	Ergon Energy	BRW
Tier (c)	153.7	146.3
MSS Gap	51.7	51.7
Total Required	**205.4**	**198.0**
Allowed in Draft Determination	174.5	174.5
EDSD Increment Over Draft Determination	30.9	23.5

All forecast figures are in June 2004 dollars. (millions)

A comparison by year of the total reliability CAPEX in the Draft Determination, the revised submission and BRW's forecast is shown in the following table:

Table 6-11: Reliability CAPEX year by year

	2005/06	2006/07	2007/08	2008/09	2009/10	TOTAL
Draft Determination	29.9	35.7	30.6	54.2	24.1	174.5
Revised Submission	29.9	51.2	46.1	54.2	24.1	205.4
BRW Forecast	29.9	47.4	42.4	54.2	24.1	198.0

All forecast figures are in June 2004 dollars. (millions)

BRW considers that the expenditure to achieve the MSSs should be classified as Tier (b) as it is directed at achieving agreed average service levels. BRW also considers that some of the expenditure on the SWER networks (discussed in Section 6.4) should be classified as Tier (c), as it is directed at improving the performance of a specific part of the network (some of the SWER expenditure has been allocated to other categories).

6.4 SWER

6.4.1 Introduction

The EDSD Report gave very clear directions that the issues of poor reliability and quality of supply on SWER networks must be addressed, and recommended the formation of a SWER Task Force to investigate available options for improvement. The report recognised that there would be a very high cost for improving reliability to SWER customers. The report also saw a need for investments in the areas serviced by SWER to be not assessed solely against commercial considerations.

Ergon Energy's original submission included programs to improve the performance of network hot spots and worst performing feeders, rather than achieving a sustainable step change in the performance of the SWER network. Since the EDSD Report was released, Ergon Energy has consulted with key stakeholders and further evaluated the operational and customer issues relating to the current performance of the SWER network, leading to the assessment of the additional funding required. Ergon Energy is aiming for a step change in performance (reduction in SAIDI and SAIFI and improved quality of supply, particularly in regard to momentary interruptions), through a combination of network and in-situ solutions. In addition, Ergon Energy aims to obtain better data through the installation of monitoring equipment, which will form the basis of more detailed planning.

6.4.2 Revised Submission

The following table summarises the additional funding requested by Ergon Energy in its revised submission (note that the expenditures are on the basis of overheads allocated to labour and materials):

Table 6-12: Revised SWER CAPEX Submission

INITIATIVE	05/06	06/07	07/08	08/09	09/10	TOTAL
Protection/Safety	0.4	0.8	0.8	1.0	1.0	4.0
Power Quality	0.15	0.6	1.15	1.6	1.5	5.0
Research & Development	0.1	0.9	1.0	1.0	1.0	4.0
Reliability	1.0	2.0	3.0	3.0	1.0	10.0
Maintenance	1.0	1.0	1.0	1.0	1.0	5.0
Data Management/Systems	0.5	0.5	0.5	0.5	0	2.0
System Augmentation	0.45	1.65	2.1	2.9	1.9	9.0
Distributed Utility	2.0	2.75	4.25	6.22	4.75	20.0
Total	**5.6**	**10.2**	**13.8**	**17.22**	**12.15**	**59.0**

All forecast figures are in June 2004 dollars. (millions)

When overheads are allocated on the basis of labour only, the $59.0M reduces very slightly to $58.7M, with the yearly allocations as shown, split into Capacity, Quality of Supply and Reliability:

Table 6-13: Revised SWER CAPEX Submission year by year

	05/06	06/07	07/08	08/09	09/10	TOTAL
Capacity	1.6	2.6	3.0	3.6	2.6	13.5
Quality of Supply	2.3	4.6	6.8	9.6	7.7	31.0
Reliability *	1.7	2.9	3.9	3.9	1.8	14.3
Total SWER EDSD Requirements	5.6	10.1	13.7	17.2	12.1	58.7

All forecast figures are in June 2004 dollars. (millions)

*Note *: Reliability in this table includes expenditure for the Reliability program in Table 6-12as well some expenditure for other programs.*

All of this forecast expenditure of $58.7Mis attributable to the EDSD report.

6.4.3 Expected Benefits

Ergon Energy expects to achieve the following benefits from the $58.7 expenditure:

- Improved supply reliability (as measured by reduced SAIDI and SAIFI);
- Improved quality of supply, through reductions in momentary interruptions and voltage dips;
- Better data about SWER reliability and quality of supply (through the installation of monitoring equipment);
- Better delivery of capacity; and
- A safer SWER network (through improved protection systems).

From Table 6-14, it can be seen that over half of the proposed expenditure is directed at improving the quality of supply, particularly in the areas of momentary interruptions and voltage dips. It is BRW's experience that quality of supply issues are becoming increasingly important to customers, with the growth in sensitive electronic devices. It is noted that Ergon Energy currently has little quality of supply data, and aims to rectify this situation through the installation of monitoring equipment. This will allow the establishment of appropriate performance targets in the future and will result in better investment decisions. Due to the lack of base data, Ergon Energy is not in a position to provide sound estimates of the expected improvements in quality of supply. Ergon Energy has made preliminary estimates of a range of 5 to 15 percent reduction in MAIFI and up to a 20 percent reduction in quality of supply complaints, over the next regulatory period.

SAIDI performance of the SWER networks is currently 2073 minutes, of which 971 is contributed by the SWER networks (the remainder is due to the upstream networks). Preliminary estimates by Ergon Energy are for a reduction in SAIDI due to the SWER networks of around 80 minutes (i.e. from 971 to 891), over the regulatory period.

Similarly, SAIFI performance of the SWER networks is currently 13.6, of which 3.7 is contributed by the SWER networks (the remainder is due to the upstream networks). Preliminary estimates by Ergon Energy are for a reduction in SAIFI due to the SWER networks of around 0.44, over the regulatory period.

The programs to achieve the expected benefits are described in more detail in the following sections:

6.4.4 Protection/Safety ($4.0M)

This program involves the upgrading of protection systems by replacing Automatic Circuit Reclosers ("ACRs") with electronic reclosers, overcoming problems with existing units not sensing earth faults (i.e. not operating when they should) and nuisance tripping (i.e. operating when they shouldn't). The estimated expenditure is based on the installation of 160 new systems at $25,000 per unit. The number of units was based on the review of some representative situations, the results of which were then extrapolated across the network. BRW considers that the method used to estimate the number of units required is appropriate, and that the numbers are reasonable.

The protection issues associated with ACRs on SWER systems are well known within the industry, and BRW considers that it is prudent asset management to address these. As well as improved safety, this program will result in reductions in SAIDI.

BRW has reviewed typical examples provided by Ergon Energy and considers the expenditure for this program to be reasonable.

6.4.5 Power Quality ($5.0M)

This program involves the installation of power quality monitoring systems across the SWER network and the installation of smart metering.

The installation of power quality monitoring systems is required to identify areas needing attention. The estimates are based on the installation of 500 units at $4,000 each. The data captured will be used in the short term to assist in identifying what needs to be done, but the data will also be monitored on an ongoing basis.

The smart metering installations are required to address system overload problems created by cold start-up after outages and to manage peak demand in key customer installations. The estimates are based on the installation of 3000 units at $1,000 each (out of a total SWER customer population of about 26,000). The number of units was based on the review of a sample SWER system, the results of which were then extrapolated across the network. BRW considers that the method used to estimate the number of units required is appropriate, and that the numbers are reasonable.

BRW considers that it is essential that Ergon Energy obtain better data relating to power quality and customer installations, and that the expenditure for this program is reasonable.

6.4.6 Research & Development ($4.0M)

This program involves research into international SWER performance solutions and implementation of trial projects. It will include the establishment of benchmarks and the identification of new technologies, performance enhancement and alternate practices.

The program includes research projects on:

- Switched reactors to improve capacity during peak load periods ($1.0M) (this estimate was based on the analysis of sample SWER schemes, extrapolated across the network);
- Optimise existing SWER operating voltages for future development purposes – trial possible 33kV or 38kV solutions ($1.0M) (the estimate is to convert one large SWER scheme as a trial);
- SVC based balancing schemes to improve power quality on 3 phase lines supplying SWER systems ($0.5M) (the estimate is to trial this for one large SWER scheme);
- Intelligent Voltage Regulators trial for improved response times, external fail indicators and improved operation of regulators in series ($0.5M) (the estimate is to develop and trial a suitable unit);
- Possible use of FACTS technology to improve quality of supply and capacity ($0.5M) (the estimate is to develop and install a pilot project); and
- Improving existing SWER 'back-up' protection to prevent plant burning down ($0.5M) (trial the use of more sophisticated protection devices).

Ergon Energy plans to conduct research in conjunction with the Central Queensland University, the Queensland University of Technology and the University of Queensland.

BRW considers that the current approaches to improving the reliability and quality of supply from SWER systems are unlikely to deliver the required improvements in performance at a realistic cost. BRW supports the need for research and development in this area and considers that the expenditure requested is reasonable.

6.4.7 Reliability ($10.0M)

This program involves the enhanced installation of ACRs, sectionalisers and line fault indicators and a range of actions to achieve improved lightning performance, including:

- Install surge-resistant fusing;
- Replace spark gaps with arrestors;
- Provide gapped earth bands or darverters on poles adjacent to transformers; and
- Retro adjust stay wires.

The expenditure can be broken down within the program as follows:

Table 6-14: SWER Reliability CAPEX Submission

	05/06	**06/07**	**07/08**	**08/09**	**09/10**	**TOTAL**
ACR Installation	500	1,000	1,500	1,500	500	5,000
Sectionaliser Installation	150	300	450	450	150	1,500
Line Fault Indicator Installation	100	200	300	300	100	1,000
Surge Resistant Fusing	50	100	150	150	50	500
Replacement of Spark Gaps	50	100	150	150	50	500
Pole Banding Adjacent to Transformers	50	100	150	150	50	500
Retro Adjust Stay Wires	100	200	300	300	100	1,000
TOTAL	**1,000**	**2,000**	**3,000**	**3,000**	**1,000**	**10,000**

All forecast figures are in June 2004 dollars. (thousands)

BRW supports the need to break the SWER network into smaller segments through the installation of ACRs and sectionalisers, as well as the installation of line fault indicators, as these actions are in line with good industry practice. BRW also supports the proposed actions to reduce the impact of lightning. BRW considers the expenditure for this program to be reasonable.

6.4.8 Maintenance ($5.0M)

This program requires additional funding to improve performance in reliability and quality, and complements existing works in the areas of:

- Ageing asset replacement;
- Conductor vibration damping;
- Deep drilled earthing program;
- Mitigation of lightning damage on reclosers and voltage regulators by construction changes;
- Access tracks to ensure fast response to fault locations; and
- Purchase of additional temporary poles for emergency repairs.

The expenditure can be broken down within the program as follows:

Table 6-15: SWER Maintenance CAPEX Submission

	05/06	06/07	07/08	08/09	09/10	TOTAL
Ageing Asset Replacement	500	500	500	500	500	2,500
Conductor Vibration Damping	100	100	100	100	100	500
Deep Drilled Earthing Program	100	100	100	100	100	500
Lightning Damage Mitigation	100	100	100	100	100	500
Access Tracks	150	150	150	150	150	750
Purchase of Temporary Poles	50	50	50	50	50	250
TOTAL	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**	**5,000**

All forecast figures are in June 2004 dollars. (thousands)

BRW considers that need for much of this work has arisen due to the lower priority previously assigned to this area. BRW considers the expenditure for this program to be reasonable.

6.4.9 Data Management & Systems ($2.0M)

This program involves the collection of accurate system data to assist with management of SWER issues. It includes:

- Extending Load Information Management System (“LIMS”) to provide periodic reports on individual SWER customer and isolation transformer loads to reduce plant overloading;
- Linking plant with Distribution System Automation (“DSA’) capability to the Supervisory Control and Data Acquisition (“SCADA”) network; and
- Purchasing portable monitoring equipment specifically to investigate problematic SWER systems.

The expenditure can be broken down within the program as follows:

Table 6-16: Data Management & System CAPEX Submission

	05/06	06/07	07/08	08/09	09/10	TOTAL
Extension of LIMS	200	50	0	0	0	250
Link DSA Capable Plant to SCADA	200	400	450	450	0	1,500
Purchase Portable Monitoring Equipment	100	50	50	50	0	250
TOTAL	**500**	**500**	**500**	**500**	**0**	**2,000**

All forecast figures are in June 2004 dollars. (thousands)

BRW considers that it is essential for Ergon Energy to have appropriate data management systems to allow effective management of the SWER network. BRW considers that the work proposed is necessary and that the expenditure for this program is reasonable.

6.4.10 System Augmentation ($9.0M)

This program includes the following:

- Replace key customer transformers with tapped units to improve customer voltages ($1.0M);
- Targeted upgrade of 11kV and 12.7kV SWER systems to 19.1kV to address quality of supply, protection and capacity issues ($5.0M); and
- Conversion of remaining non-isolated SWER systems to isolated SWER for protection enhancement ($3.0M).

The expenditure can be broken down within the program as follows:

Table 6-17: System Augmentation CAPEX Submission

	05/06	06/07	07/08	08/09	09/10	TOTAL
Tapped Transformers	50	50	200	400	300	1,000
Upgrades SWERs to 19.1kV	100	1,000	1,000	1,600	1,300	5,000
Isolation of SWERs	300	600	900	900	300	3,000
TOTAL	**450**	**1,650**	**2,100**	**2,900**	**1,900**	**9,000**

All forecast figures are in June 2004 dollars. (thousands)

BRW considers that the proposed works are sensible and in line with good industry practice. BRW considers the expenditure for this program to be reasonable.

6.4.11 Distributed Utility ($20.0M)

This program includes the following projects:

- Installation of short-term energy storage units to overcome momentary outages and reduce fluctuations ($10.0M);
  - Estimate based on installation of 2000 units at $3,500 each plus research and extended trials; and
  - Number of units determined by assessment that approximately 10% of situations would not be capable of being resolved by traditional network approaches at acceptable costs.
- Embedded Generation trials - installation of small scale generation at key points in the SWER network to improve voltage and quality of supply ($6.0M); and
  - This project has a large research and development component and will involve a small number of trial units; and
  - Involves the installation of regulated assets on customers' premises.
- Implement Demand Side Management ("DSM") Programs to improve SWER system load factors and increase available capacity ($4.0M).
  - Stage one: "DSM feasibility project" ($1.0M) – this phase involves obtaining base data regarding customer needs, customer usage patterns etc and developing a program; and
  - Stage two: implement cost-effective DSM projects ($3.0M).

This program covers the development of some new approaches to resolving SWER issues, and as such is supported by BRW, as reliance on more traditional methods will not be cost effective in all cases. BRW considers the expenditure for this program to be reasonable.

6.4.12 Conclusions

BRW supports the proposed mix of traditional approaches and the development of new solutions, particularly the move to include installations on customers' premises. The need for increased monitoring equipment is strongly supported as a basis for improved management of the SWER network. BRW considers that the issues with SWER systems will take many years to address and will cover several regulatory periods. In this forthcoming regulatory period, the emphasis will be on gaining information about the SWER network and customer expectations, to allow more rigorous estimates to be made of work required in the following period. Ergon Energy has projected improvements in reliability and quality of supply that BRW considers to be consistent with the work proposed, bearing in mind the need for research and development and monitoring. BRW considers the costs for the works on the SWER network to be consistent with the expanded outcomes and supports the need for this expenditure.

6.5 Major Customers

The forecasts in this section relate only to major customer projects, and exclude the other customer initiated categories (e.g. Domestic/Rural, Subdivisions, Public Lighting etc.).

6.5.1 Draft Determination

Major Customers have been split into the following three categories:

- Category 1: Projects with a reasonable degree of certainty (80% and greater) or a value less than $5m;
- Category 2: Known projects which are likely to proceed, but the timing and/or the cost is uncertain (less than 80%) and having a value equal to or greater than $5m: and
- Category 3: Projects which are unknown at the present time.

The Draft Determination provided for the following split between the three categories:

Table 6-18: Draft Determination Major Customers CAPEX

	CAPEX for 2005/06-09/10
Category 1	38.0
Category 2	107.0
Category 3	66.4
Total	**211.4**
Eligible for Pass-Through (Categories 2 & 3)	173.4

All forecast figures are in June 2004 dollars. (millions)

The Draft Determination proposed a pass-through mechanism for Ergon Energy to accommodate identified capital projects totaling $173.4M that are likely to proceed during the next regulatory period, but with a probability of proceeding of less than 80 per cent. Each project will also have to have a potential cost of at least $5M. The Draft Determination also proposed to consider pass-through for large customer projects, with a cost in excess of $30M, that occur during the next regulatory period but were totally unanticipated.

6.5.2 Revised Submission

Since Ergon Energy's original submission was prepared, there has been a major expansion of large coal projects, with the associated requirement for additional infrastructure (particularly new and expanded port facilities). In addition, a number of projects have firmed up since the original submission. As a result, Ergon Energy has revised its submission as follows:

Table 6-19: Revised Submission Major Customers CAPEX

	CAPEX for 2005/06-2009/10
Category 1	141.1
Category 2	421.2
Total	**562.3**

All forecast figures are in June 2004 dollars. (millions)

In reviewing the spreadsheet supporting the revised submission for major customers, BRW discovered an error (confirmed with Ergon Energy) in the totals for Category 1, which should be $162.3M and Category 2 (derived by subtraction from the total), which should be $400.0M. Of the 26 projects included in the original submission (excluding the construction phase), 16 have no change to the cost estimates, with several projects showing a significant increase in costs (attributable to a more definite scope of works with updated information). The major reason for the increase in the cost for major projects in the revised submission is an increase in the number of projects - an additional 39 projects have been included at a cost of $99.9M.

Ergon Energy has provided supporting information to substantiate the changes in the revised submission. BRW is aware of recent announcements relating to significant expansion of coal mining activity and the consequent requirement for additional infrastructure. BRW considers that Ergon Energy's revised estimates (after correction for errors) for major customers are reasonable.

6.5.3 Pass-Through Mechanism

The $173.4M set aside for potential pass-through in the Draft Determination was made up of $107M for Category 2 projects and an allowance of $66.4M for Category 3 projects (refer to Table 9-31, Page 105, BRW Final Report). Given the recent volatility of estimates for major projects, both in terms of numbers of projects and costs, it is difficult to arrive at a meaningful estimate of how much to allow for the smaller unknown projects. This difficulty could be overcome to some extent by providing some further flexibility in the pass-through mechanism.

Ergon Energy have requested a change to the pass-through mechanism for projects that are totally unanticipated at the time of the submission. The Draft Determination specified that a project would need to be in excess of $30M to be eligible for pass-through. Ergon Energy suggests that this approach be modified to allow the aggregation of projects (each in excess of $5M) in blocks of a minimum of $20M, on the basis that very few projects would exceed the $30M threshold. In analysing the projects currently at the pre-feasibility, enquiry and application phases, BRW has identified three projects $30M or over, totalling $117M, and 28 projects over $5M, totalling $480M.

6.5.4 Conclusions

BRW considers that it is not appropriate to include a set allowance for unknown projects, but instead allow some additional flexibility in the pass-through mechanism. BRW supports the approach suggested by Ergon Energy, with the exception that the minimum blocks for aggregation be increased to $30M to reduce the frequency of such matters being referred to the QCA.

A comparison between Ergon Energy's revised submission and the estimates made by BRW are shown in the attached table:

Table 6-20: Major Customers CAPEX

	ERGON ENERGY	BRW
Category 1	141.1	162.3
Category 2	421.2[1]	400.0
Category 3	66.4[1]	0
Total	**628.7 [1]**	**562.3**
Eligible for Pass-Through (Categories 2 & 3)	487.6[1]	400.0

All forecast figures are in June 2004 dollars. (millions)

Note 1: These figures are implicit in the revised submission.

6.6 Building Costs

6.6.1 Revised Submission

The following table provides a comparison between the Draft Determination and Ergon Energy's revised submission for Land & Buildings:

Table 6-21: Revised Submission Land and Buildings CAPEX

	05/06	06/07	07/08	08/09	09/10	TOTAL
Draft Determination	12.0	12.0	12.0	12.0	12.0	60.0
Revised Submission	20.0	15.0	15.0	15.0	15.0	82.0
Increase	8.0	3.0	3.0	3.0	3.0	20.0

All forecast figures are in June 2004 dollars. (millions)

Ergon Energy has attributed the increases to the following three factors:

- Increased staff numbers;
- Additional work identified by a Property Condition Assessment program; and
- Increases in building costs in regional Queensland.

Increased Staff Numbers

Most of Ergon Energy's existing accommodation is at or nearing capacity, with many capital projects planned for 2005/06 and subsequent years. The major regional hubs of Townsville, Toowoomba and Rockhampton require significant capital investment to cater for the predicted increase in staff numbers. At the time of the original submission, increased staff numbers were proposed but they were not site specific. There is now a clearer picture of the impact on the building program. Master planning studies are under way to develop 10-15 year site development plans; although these are not completed the work so far has provided input to the revised estimates.

Additional Work Identified Through Property Condition Assessment Program

Since preparing the original submission, Ergon Energy has conducted a Property Condition Assessment program, which identified a range of capital works to address issues of building condition, Workplace Health and Safety and operational requirements. A very detailed assessment was conducted for each site, providing a sound basis for identifying and prioritising the necessary work. The previous approach taken by Ergon Energy was purely reactive, with the result that some maintenance items now appear as capital issues.

Increases in Building Costs

Since the original submission was prepared, there have been significant increases in building costs in Regional Queensland. This is attributable to the significant growth in the building industry, driven by a housing boom. Ergon Energy claims that this has resulted in increases of as much as 50% in 6 months in building estimates in regional Queensland and up to 80% in more remote areas. Building costs are not expected to continue to increase at such rates, but are likely to remain at the higher levels in the medium term, partly due to a continuing shortage of skilled labour in regional areas.

6.6.2 Conclusion

BRW is satisfied that Ergon Energy now has a more rigorous approach to managing its property program and that there have been significant changes since the original submission. BRW considers that the revised estimates are reasonable. BRW has also transferred an additional $1.4M into this category (refer to Section 6.8.3).

A comparison between the revised submission and BRW's forecast is shown in the following table:

Table 6-22: Revised Submission and BRW Forecast Land and Buildings CAPEX

	05/06	06/07	07/08	08/09	09/10	TOTAL
Revised Submission	20.0	15.0	15.0	15.0	15.0	82.0
BRW Forecast	20.5	15.8	15.1	15.0	15.0	83.4

All forecast figures are in June 2004 dollars. (millions)

6.7 EBA CAPEX Impacts

Ergon Energy's revised submission contains an amount of $61.7M for wage and salary increases arising from the EBA, spread as follows:

Table 6-23: Revised Submission EBA CAPEX Breakdown

	05/06	06/07	07/08	08/09	09/10	Total
Asset replacements	3.5	5.1	5.6	5.8	5.8	25.8
Augmentations	1.6	2.3	2.5	2.6	2.6	11.5
Customer initiated	2.5	3.7	4.1	4.2	4.2	18.7
Reliability Improvement	0.6	0.8	0.9	0.9	0.9	4.1
System - Other	0.2	0.3	0.4	0.4	0.4	1.6
Non-System	0.0	0.0	0.0	0.0	0.0	0.0
Total CAPEX EBA	**8.4**	**12.1**	**13.4**	**13.8**	**13.9**	**61.7**

All forecast figures are in June 2004 dollars. (millions)

The quantum of the EBA increases and the allocation between OPEX and CAPEX are discussed in further detail in Section 7. For CAPEX, BRW has reduced the EBA allowance from $61.7M to $53.8M, as explained in Section 7. The impact is shown in the following table.

Table 6-24: Revised Submission EBA CAPEX Impact

	05/06	06/07	07/08	08/09	09/10	TOTAL
Revised Submission	8.4	12.1	13.4	13.8	13.9	61.7
BRW Forecast	7.3	10.6	11.7	12.0	12.1	53.8

All forecast figures are in June 2004 dollars. (millions)

6.8 Increased Market Rates

Ergon Energy has identified three key areas in which significant increases have occurred:

- Subtransmission line construction, including the cost of contract work;
- Substation works, including the cost of contract work; and
- Land acquisition costs.

The following costs apply to projects that were included in the original submission. For new projects or projects with a change in scope, the additional costs have been included in other categories. BRW has viewed the spreadsheet underpinning the categorisation of the increases and is satisfied that there has been no "double counting".

6.8.1 Subtransmission Lines ($16.7)

Cost increases in this area are attributed by Ergon Energy mainly to increases in contract costs and a range of other increases.

Increased Contract Costs

The majority of sub-transmission works (both underground and overhead) are largely constructed by contract resources, and the cost of such works has increased significantly since the original submission. The costs included in the revised submission are based on current average contract and material rates.

Other Increases

Ergon Energy has identified a range of other factors which has lead to cost increases, including:

- Increasing difficulties in line route acquisition, often resulting in longer line lengths, more bends, and the increased use of underground and double circuit overhead construction;
- Increased property procurement costs to obtain vegetation clearing and cultural heritage approvals;
- Changes to standard designs (e.g. conductor rationalisation and use of Optical fibre Ground Wire ("OPGW") as the earth wire for sub-transmission lines);
- Increases in key material costs (concrete poles, conductors); and
- Significant increases in civil works (particularly trenching costs for underground cable projects).

Conclusion

BRW considers that this matter is related to the issue of unit rates (as discussed in Section 6.2.4) and should be debated further between Ergon Energy and the QCA. For consistency, BRW has removed this item from the estimates.

6.8.2 Substation Works ($32.3)

Cost increases in this area are attributed by Ergon Energy to increases in contract costs and a number of other increases.

Increased Contract Costs

Ergon Energy has experienced increased contract costs from the panel of preferred contractors, of between 10-30%, in comparison to Ergon Energy's internal costs. This is presumably due to the constrained contract market and Ergon Energy has assumed that this will continue over the regulatory period.

Other Increases

As for sub-transmission lines, there has been a significant increase in the cost of civil works and material items (e.g. transformers and cable).

Conclusion

As for Subtransmission Lines, BRW considers that this matter is related to the issue of unit rates and should be debated further between Ergon Energy and the QCA. For consistency, BRW has removed this item from the estimates.

6.8.3 Land Acquisition ($1.4M)

Land acquisition costs for substation sites have increased due to the demand for property in Queensland regional cities. BRW considers the cost increases for substation sites to be reasonable, but that these costs should be included in the Land and Buildings category. Accordingly, BRW has removed this item form the "Market Rates" category and included it under "Land & Buildings."

Ergon Energy has advised that the fall of the additional $1.4M is as follows:

Table 6-25: Land Acquisition CAPEX

	05/06	06/07	07/08	08/09	09/10	TOTAL
Additional site acquisition costs	0.5	0.8	0.1	0	0	1.4

All forecast figures are in June 2004 dollars. (millions)

6.8.4 Summary

A comparison between Ergon Energy's and BRW's estimates for Increased Market Rates is shown in the following table:

Table 6-26: Summary Comparison of Ergon Energy and BRW estimate for Increased Market Rates

AREA	Ergon Energy	BRW
Sub-transmission Lines	16.7	0
Substations	32.3	0
Land Acquisition	1.4	0 *
Total	**50.4**	**0**

All forecast figures are in June 2004 dollars. (millions)

Note *: Transferred to Land & Buildings

6.9 Revised CAPEX Forecast

A comparison between Ergon Energy's revised submission and BRW's forecast, with the estimates for SWER, EBA and Market Rates allocated across the appropriate expenditure areas, is shown in the following table.

Table 6-27: Revised CAPEX Forecast

AREA	DRAFT DETERMINATION	REVISED 2005 SUBMISSION	BRW 2005 FORECAST
Asset Replacement	655.4	686.1	682.8
Augmentation	505.2	778.6	722.5
Customer Initiated	580.8	702.3	721.4
Reliability	174.5	235.1	227.2
Other System	45.9	58.5	58.3
Non-System	335.1	355.1	356.5
TOTAL	**2,296.9**	**2,815.7**	**2,768.7**
Eligible for Pass-Through	173.4	487.6	400.0

All forecast figures are in June 2004 dollars. (millions)

In its revised submission, Ergon Energy has applied smoothing to the CAPEX to allow a better match with resources. The unsmoothed and smoothed CAPEX is shown in the following table:

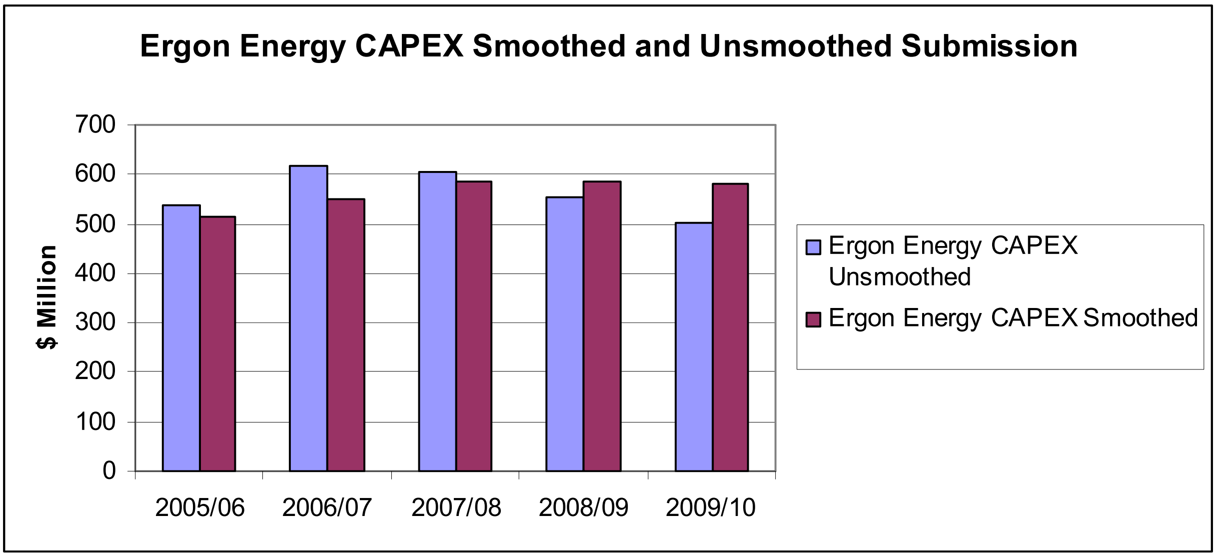
Table 6-28: Smoothed and Unsmoothed CAPEX Submission

	05/06	06/07	07/08	08/09	09/10	TOTAL
Unsmoothed	538.2	616.5	605.3	555.2	500.4	2,815.7
Smoothed	515.9	549.8	584.7	585.3	579.9	2,815.7

All forecast figures are in June 2004 dollars. (millions)

This is shown on the following graph:

Figure 6-1: Smoothed and Unsmoothed Ergon Energy CAPEX Submission



All forecast figures are in June 2004 dollars. (millions)

BRW supports this approach, to allow a more gradual ramping up of resources. Clearly, Ergon Energy will need to carefully manage the deferral of works from the early period, especially in 2006/07.

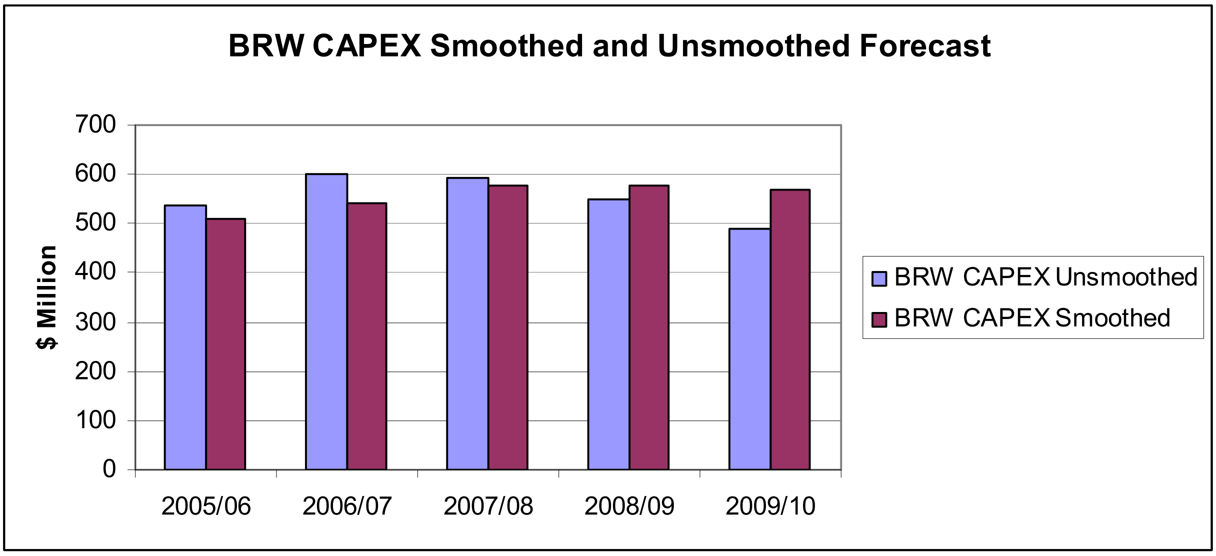
BRW has applied Ergon Energy's smoothing profile to BRW's revised estimates as follows:

Table 6-29: Smoothed and Unsmoothed BRW CAPEX Forecast

	05/06	06/07	07/08	08/09	09/10	TOTAL
BRW Unsmoothed	537.6	600.8	591.6	548.4	490.2	2,768.7
BRW Smoothed	507.3	540.6	575.0	575.6	570.2	2,768.7

All forecast figures are in June 2004 dollars. (millions)

Figure 6-2: Smoothed and Unsmoothed BRW CAPEX Forecast



All forecast figures are in June 2004 dollars. (millions)

A consolidated CAPEX comparison, showing the major categories contained in the Draft determination, is shown in Section 10.3.

7 EBA

Coincident with the establishment of a new EBA in 2005 were a number of recommendations from the EDSD report requiring both DSNPs to develop a resource plan and implement a training strategy to overcome the difficulties associated with:

- An ageing workforce, particularly in the field;
- Lack of personnel to complete operational and capital work programs;
- Shortage of suitably trained personnel in Queensland; and
- A major risk that the networks may not be adequately maintained and augmented.

This EBA has been developed in conjunction with government bodies and Energex to overcome this position.

Consideration has been given to other government instrumentalities and awards applying to NSW DSNPs.

The Table 7-1, supplied by Ergon Energy, shows the existing salary differences between typical workers in comparative DNSPs. BRW has confirmed the PowerCor figures.

Table 7-1: Comparative salaries of typical workers in differing DNSPs

	Hrs / week	Senior Linesperson	Senior Electrical Tradesperson (Substations)	Senior Testing/Commissioning Technician
Energex	36.25	$45,785 (TS4 SP 7.0)	$45,785 (TSP4 SP 7.0)	$50,441 - $65.896 (PP2 – PP4)
Ergon Energy	36.25	$46,122 (TSP4 SP 7.0)	$46,122 (TSP4 SP 7.0)	$50,841 - $66,382 (PP2 – PP4)
Proposed Energex & Ergon Energy		$50,672	$50,672	$55,538 - $71.688
ActewAGL	36.75	$50,057	$50,057	$50,057
ETSA	37.5 (4% min increase expected	$44,928	$50,440	$56,000 - $63,200
PowerCor		$49,677 (incr to $51,780 Sep 2005)	$52,628 (incr to $54,864 Sep 2005)	$60,283 (incr to $63,077 Jul 2005)
Energy Australia		$53,946	$58,411	$58,411 - $70,000

Agreement with unions and appropriate bodies is expected to be completed shortly and estimates for the next regulatory period have been based on an EDSD Network Recovery, Attraction and Retention Allowance and Payment.

The components of Ergon Energy's revised submission consist of:

- The Agreement provides for a guaranteed compounding salary increase following certification of 3.5% wage adjustment plus a further 1% productivity payment for a total of 4.5% for each year of this EBA. The previous EBA of 4% has been absorbed by Ergon Energy in productivity gains and the CPI increases. The submission includes an additional 0.5% per year which represents productivity gains;

- Other allowances associated with this EBA including increases in overtime meal allowances standby allowance, employee in charge allowance, overtime phone calls, drivers licence, maternity and paternity leave and funeral benefit;
- An amount relating to parity payments had not been included in the 2004 submission. Its inclusion in the revised submission follows recent settlement of a standardised wage scale to ensure that all staff from the previous electricity entities are paid the same amount for similar positions;
- An all purpose allowance paid to employees in the Technical Classification Stream of:
    - $54.37 per week on certification of the Agreement;
    - $90.62 per week on or after 16 February 2006; and
    - $110.55 per week on or after 16 February 2007.
- A payment to employees in the Administration and the Professional and Managerial Streams in recognition of their contribution to the EDSD network recovery program of:
    - $1,500 paid following certification of this agreement;
    - $1,000 paid following 16 February 2006; and
    - $500 paid following 16 February 2007.
- Provision for relief white collar contract staff for call centre and information technology;
- Superannuation payment of one additional unit of temporary disablement cover for defined contribution members; and
- Provision for increased payments to contractors associated with CAPEX and OPEX contracts. It has been assumed that existing contracts will continue at the current rates until the contracts are renewed.

The forecast costs for these components are summarised in Table 7-3. Note that capital and operation expenditure for each year of the regulatory period has been based on the proportion of CAPEX and OPEX for the current year. These costs can be further apportioned across each CAPEX and OPEX program according to the cost of each program.

The cost will be offset by an agreement which is part of the EBA related to an acceptance of the principles of workplace change and flexibility and striving towards the objectives outlined in the EDSD Network Recovery Review and the Electricity Industry Code.

Other factors which support the extent of the EBA increase include:

- The EDSD Review recommendations and the development of the Resourse Plan for the next 5-10 years to address the aging workforce and anticipated skill shortages;
- Support through participation with government organisations and Energex;
- The need to attract suitably skilled persons from the Southern states and other industries in Queensland; and
- The need to arrest the drain of contract workforce to other states because of higher pay rates in the main skill shortage areas.

BRW is of the view that the 0.5% component, which represents a productivity gain, should be absorbed and have consequently removed it from the forecast.

BRW's revised forecast is $155.4M over the five year regulatory period as shown in Table 7-3. Given the need to attract and retain staff in order to resource proposed capital and operational programs for the next regulatory period, BRW considers that the revised additional costs associated with the new EBA are reasonable.

Table 7-2 shows a comparison of revised EBA forecast for Ergon Energy with that of Energex. It can be seen that although the number of employees impacted by the EBA in both organisations is similar, the EBA forecast for Ergon Energy is significantly greater ($75.4M) than the Energex forecast. However, the Ergon Energy forecast includes external labour and parity EBA impacts which are not included in the Energex forecast. These impacts amount to $77.65M. Given their greater reliance on external labour, the EBA submission for Ergon Energy is considered comparable with that of Energex.

Table 7-2: EBA Costs – Comparison with Energex

	No. of Employees Impacted by the EBA			Submission for EBA by DNSP	BRW Revised EBA
	Technical Stream	Managerial and Admin. Stream	Total		
Ergon Energy	1,600	1,370	2,970	184.4	155.4
Energex	1,507	1,350	2,857	90.1	80.0

Table 7-3: EBA Costs (incl. overheads allocated at 55%)

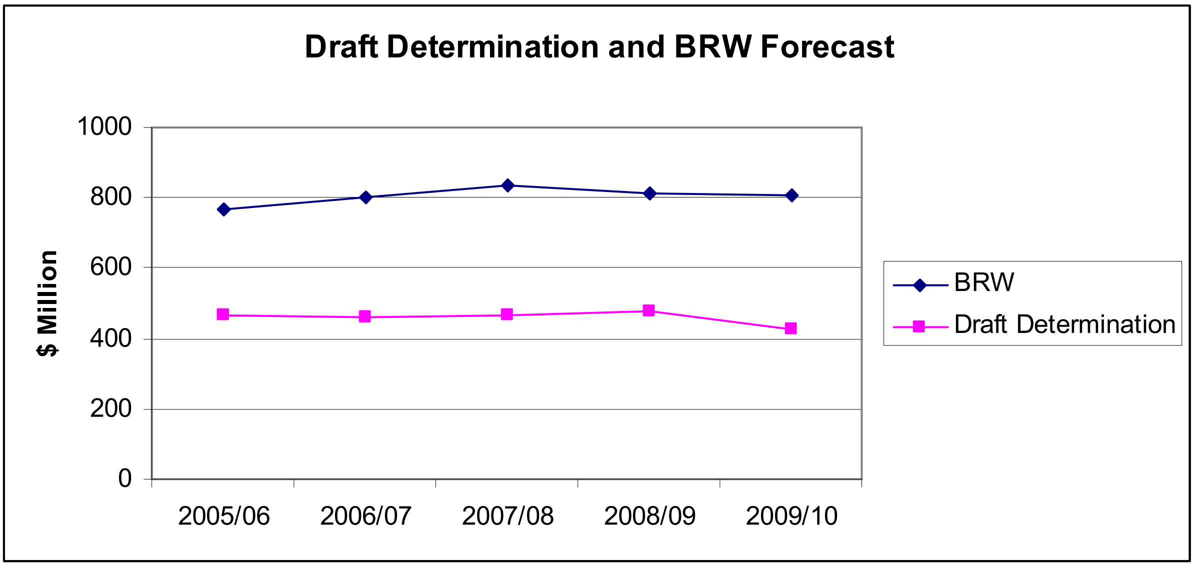
Area	05/06			06/07			07/08			08/09			09/10			TOTAL		
	Impact ($M)	OPEX ($M)	CAPEX ($M)	Impact ($M)	OPEX ($M)	CAPEX ($M)	Impact ($M)	OPEX ($M)	CAPEX ($M)	Impact ($M)	OPEX ($M)	CAPEX ($M)	Impact ($M)	OPEX ($M)	CAPEX ($M)	Impact ($M)	OPEX ($M)	CAPEX ($M)
1. Increase EBA from 4% to 4.5%	2.22	1.43	0.79	3.47	2.23	1.24	4.66	3.00	1.67	5.80	3.73	2.07	6.89	4.43	2.46	**23.05**	**14.82**	**8.23**
2. Other EBA Allowances	1.91	1.09	0.82	1.89	1.08	0.81	1.90	1.08	0.82	1.94	1.10	0.83	1.97	1.13	0.85	**9.61**	**5.48**	**4.13**
3. Parity Cost	1.72	0.98	0.74	1.75	1.00	0.75	1.79	1.02	0.77	1.82	1.04	0.78	1.86	1.06	0.80	**8.94**	**5.09**	**3.84**
4. EDSD Recovery Attraction & Retention Payment (Special Technical and Field Staff)	11.61	7.85	3.76	13.75	8.49	5.25	13.61	7.76	5.85	13.28	7.57	5.71	12.95	7.38	5.57	**65.20**	**39.05**	**26.15**
5. EDSD Recovery Attraction & Retention Payment (Admin, Manegerial and Professional)	1.51	0.86	0.65	0.74	0.42	0.32	-	-	-	-	-	-	-	-	-	**2.25**	**1.28**	**0.97**
6. White collar external labour EBA impact	2.00	1.14	0.86	2.04	1.16	0.88	2.08	1.19	0.90	2.12	1.21	0.91	2.16	1.23	0.93	**10.42**	**5.94**	**4.48**
7. Temporary Disablement Superannuation Payments	0.13	0.07	0.06	0.13	0.08	0.06	0.13	0.08	0.06	0.14	0.08	0.06	0.14	0.08	0.06	**0.67**	**0.38**	**0.29**
8. Blue collar contractor EBA impact	3.56	2.71	0.85	11.73	8.93	2.80	14.23	10.84	3.39	14.35	10.93	3.42	14.46	11.01	3.45	**58.32**	**44.42**	**13.90**
Total EBA Impact	**24.66**	**16.13**	**8.53**	**35.50**	**23.40**	**12.11**	**38.40**	**24.96**	**13.45**	**39.45**	**25.66**	**13.79**	**40.44**	**26.32**	**14.12**	**178.45**	**116.46**	**61.99**
Overhead Adjustments	0.80	0.91	-0.11	0.70	0.68	0.02	0.80	0.80	0.00	1.59	1.61	-0.02	2.11	2.32	-0.21	5.99	6.31	-0.32
Total EBA Impact with Overhead Adjustments	**25.46**	**17.04**	**8.42**	**36.20**	**24.08**	**12.13**	**39.20**	**25.75**	**13.45**	**41.04**	**27.26**	**13.77**	**42.55**	**28.64**	**13.91**	**184.44**	**122.77**	**61.67**
BRW Revised EBA (without Item 1 above)	**22.44**	**14.70**	**7.74**	**32.03**	**21.17**	**10.87**	**33.74**	**21.96**	**11.78**	**33.65**	**21.93**	**11.72**	**33.55**	**21.89**	**11.65**	**155.41**	**101.64**	**53.76**

All forecast figures are in June 2004 dollars (millions)

8 RESOURCING

The following graph shows the total CAPEX and OPEX for both the Draft Determination and for BRW's forecast.

Figure 8-1: Draft Determination and BRW Forecast



All forecast figures are in June 2004 dollars. (millions)

To meet the increased level of work, Ergon Energy has updated its detailed Resource Plan which explains its resource planning process, activities to develop the skills required to deliver the works program, recruitment activities, resourcing from external service providers and the strategies moving forwards. In developing its Resource Plan, Ergon Energy has taken account of the EDSD comments and recommendations relating to resourcing and training. Implicit in the plan is the premise that the new EBA will provide parity with other States and industries, thus facilitating the recruitment and retention of personnel in an environment of a shortage of skilled personnel.

8.1 Internal Staffing

Ergon Energy has significantly increased its internal resources, with 100 additional people (directly related to delivering the workplan) appointed in the six months up to Christmas 2004. Ergon Energy has taken on two apprentice intakes per year of 40 apprentices for each intake, for the last 2 years, and 38 apprentices are due to graduate in the next six months. Ergon Energy has employed external consultants to assist in developing more effective strategies and is implementing a more targeted advertising campaign, including:

- Recruiting overseas (South Africa and Ireland);
- Attracting apprentices who have finished their time in other organisations and who are not indentured;
- Targeting Queensland Rail employees; and
- Attracting tradespersons from the mining industry.

The new EBA will restore parity with wage rates in NSW and Victoria, making it far easier to attract and retain employees.

The Resource Plan takes into account attrition rates, the work force age profile, the capacity of the organisation to integrate large numbers of new employees, productivity improvements through improved work planning, innovative approaches to training, development of existing personnel, new approaches to recruitment and the more effective use of contractor panels.

An area of concern from BRW's earlier review was technicians in the area of secondary maintenance and commissioning. Ergon Energy has been able to attract skilled para-professionals and is currently in a selection process with some 30 applicants from Ireland. Ergon Energy has established training courses and is currently training 13 para-professionals, and is planning to appoint and train a further 12 people in the area of distribution design.

Although the recruitment and retention of adequate numbers of appropriately skilled personnel will be an ongoing issue, BRW considers that Ergon Energy is taking the appropriate actions to obtain the required levels of personnel and has demonstrated success in this area.

8.2 Contract

Contractors form a significant resource for delivery of the works program – it is expected that they will deliver up to 20% of the works program (excluding Vegetation Management and Asset Inspection).

In the case of vegetation management and asset inspections, contractors are expected to deliver 100% of the program.

Ergon Energy is making use of panels of approved contractors and has reduced the number of small contractors. Contractors on the panels are larger companies with good resources and effective management systems and practices. Contractors have been provided with increased security of work, enabling them to appropriately resource, refine their processes and develop their culture to work alongside the Ergon Energy workforce.

There is a panel for distribution works, covering mainly remediation and smaller construction works. For transmission works, there are two panels – one for design and one for design and construct. There is spare contractor capacity, particularly in the transmission panels (currently there is 85,000 hours being delivered by the transmission panels and it is planned to increase this to 200,000 hours in 2005/06).

8.3 Conclusions

Although BRW is reasonably confident of Ergon Energy's capability to resource the forecast workload over the forthcoming regulatory period, there is some risk that Ergon Energy will not be able to deliver an expenditure program of this size. To mitigate this risk, BRW recommends that the QCA allow for only 90% of the CAPEX (i.e. $2,492.1M) to be initially included in Ergon Energy's revenue cap, with provision for Ergon Energy to increase this amount (up to $2,769M) on demonstration of the need and capacity to wisely invest the full amount.

9 GLOSSARY

ABS	Air Break Switch
ACR	Auto Reclosers
BRW	Burns and Roe Worley Pty Ltd
CAPEX	Capital expenditure
DNSP	Distribution Network Service Provider
Draft Determination	Draft determination, Regulation of Electricity Distribution
DSA	Distribution System Automation
DSM	Demand Side Management
EBA	Enterprise Bargaining Agreement
EDSD	Electricity Distribution and Service Delivery Review
GSL	Guaranteed Service Level
HV	High voltage
kV	Kilo volts i.e. 1,000 volts
LIMS	Load Information Management System
LV	Low voltage
MAIFI	Momentary Average Interruption Frequency Index
MD	Maximum Demand
MMA	McLennan Magasanik Associates Pty Ltd
MVA	Mega volt amps i.e.1,000,000 volt amps
MWh	Mega watt hours i.e. 1,000,000 watt hours
MW	Mega watts i.e.1,000,000 watts
MSS	Minimum Service Standards
OPEX	Operating expenditure
OPGW	Optical fibre Ground Wire
PANEL	Independent Panel of the Electricity Distribution and Service Delivery Review
PoE10	Probability of Exceedence of 10%
QCA	Queensland Competition Authority
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SKM	Sinclair Knight Mertz
SNAPS	Sub-transmission Network Augmentation Plans
SWER	Single Wire Earth Return
URD	Underground Residential Distribution

10 APPENDICES

10.1 Interviews

DATE & LOCATION	BRW PERSONNEL	KEY ERGON ENERGY PERSONNEL	TOPIC
17/2/05 Brisbane	Ian Marks Graham Batcheler	Leigh D'Arcy Col Lawson Tony Loveday Paul Asnicar	Overview of changes since BRW review
17/2/05 Brisbane	Ian Marks Graham Batcheler	Greg Nielsen Jon Turner Gordon Binks (phone) Tony Loveday Leigh D'Arcy Col Lawson Paul Asnicar	SWER
17/2/05 Brisbane	Ian Marks Graham Batcheler	Tony Loveday Leigh D'Arcy Col Lawson Paul Asnicar	Augmentation
17/2/05 Brisbane	Ian Marks Graham Batcheler	Leigh D'Arcy Col Lawson Tony Loveday Paul Asnicar	Market rates
17/2/05 Phone Hook-up	Erika Twining Jeff Randles	Ken Ash David Wood Tony Pfeiffer	Vegetation
18/2/05 Brisbane	Ian Marks Graham Batcheler	Mike Dougan Leigh D'Arcy Paul Asnicar	Major customers
18/2/05 Brisbane	Ian Marks Graham Batcheler	Peter Hulme (phone) Leigh D'Arcy Paul Asnicar	Resources
18/2/05 Brisbane	Ian Marks Graham Batcheler	Gary Hunter Leigh D'Arcy Paul Asnicar	Reliability
18/2/05 Brisbane	Erika Twining Jeff Randles	Greg Evans Roger Glover Tony Pfeiffer	EBA / Separate Accounts
18/2/05 Brisbane	Erika Twining Jeff Randles	Greg Nielsen Fraser Power Tony Pfeiffer	GSLs
18/2/05 Brisbane	Erika Twining Jeff Randles	Malcolm Tadgell Tony Pfeiffer	Reporting

DATE & LOCATION	BRW PERSONNEL	KEY ERGON ENERGY PERSONNEL	TOPIC
18/2/05 Brisbane	Erika Twining Jeff Randles	Damian McKenzie-McHarg Malcolm Tadgell Tony Pfeiffer	Self Insurance
22/2/05 Phone Hook-up	Ian Marks Graham Batcheler	Scott Birgan Paul Asnicar	Building costs

10.2 Key Documents Accessed

QCA Draft Determination, Regulation of Electricity Distribution, December 2004

Electricity Industry Code, December 2004

Detailed Report of the Independent Panel, Electricity Distribution and Service for the 21st Century, Queensland, July 2004

2005 Electricity Distribution Review, Electricity Distribution Service Delivery, Submission to QCA, Ergon Energy, 21 January

Network Management Plan, 2004-2010

Resource Plan for QCA Determination February 2005

Response to BRW CAPEX Questions for Ergon Energy 1

Response BWR CAPEX Questions V3

5-Year Sub-transmission Network Augmentation Plan 2004 (one for each Region)

Regional Capability Review and 5-Year Augmentation Plan 2004 (one for each Region)

Ergon Energy Summer 2004/05 Preparations, August 2004

Ergon Energy Analysis of Monthly Government Reporting, January 2005

Ergon Energy Certified Agreement, 2005-03-02

Response to BRW OPEX Questions for Ergon Energy, February 2005-03-02

Electrical Safety Office, Improving Electricity Distribution Entities’ Vegetation Management Systems for a Safer Queensland, February 2005-03-02

SAHA International, Distribution Business Self-Insured Risks – Order of Magnitude Summary Draft Report, 3 November 2004

Code of Practice – Powerline Clearance (Vegetation), 2002

Asset Maintenance and Replacement Plan – Vegetation Management & Access Track Maintenance, January 2005

10.3 Consolidated OPEX forecasts

Table 10-1: Consolidated OPEX Forecasts with Distributed EBA

	05/06	06/07	07/08	08/09	09/10	TOTAL
DRAFT DETERMINATION						
Maintenance						
Lines	91.95	93.13	92.86	77.53	78.78	434.24
Vegetation	48.56	48.87	48.62	55.21	55.72	256.98
Substations	22.42	22.74	22.80	23.58	24.15	115.68
Meters	2.89	3.49	3.52	3.86	4.45	18.21
Total Maintenance	**165.83**	**168.22**	**167.79**	**160.18**	**163.09**	**825.11**
Operations						
Network Operations	11.80	11.87	11.81	12.11	12.30	59.89
Customer Service	31.95	32.71	33.10	34.51	35.67	167.94
Total Operations	**43.75**	**44.58**	**44.92**	**46.62**	**47.97**	**227.84**
Total OPEX	**209.58**	**212.80**	**212.71**	**206.80**	**211.06**	**1,052.95**
REVISED ERGON ENERGY FORECAST (2005)						
Maintenance						
Lines	99.09	103.21	103.65	88.95	90.78	485.68
Vegetation	84.77	83.03	82.01	69.32	67.64	386.76
Substations	23.12	23.73	23.86	24.70	25.32	120.72
Meters	3.01	3.65	3.69	4.04	4.64	19.04
Total Maintenance	**209.98**	**213.62**	**213.20**	**187.01**	**188.38**	**1012.20**
Operations						
Network Operations	13.03	13.62	13.68	14.08	14.37	68.78
Customer Service	34.08	35.53	36.09	37.67	38.98	182.35
Self Insurance Costs	3.30	3.24	3.26	3.40	3.50	16.70
Total Operations	**50.41**	**52.38**	**53.03**	**55.15**	**56.86**	**267.82**
Total OPEX	**260.39**	**266.00**	**266.23**	**242.16**	**245.24**	**1280.02**
REVISED BRW FORECAST (2005)						
Maintenance						
Lines	98.11	102.00	102.06	86.72	87.95	476.84
Vegetation	83.92	81.98	80.64	65.30	63.22	375.05
Substations	23.02	23.61	23.70	24.48	25.05	119.85
Meters	2.99	3.63	3.67	4.01	4.60	18.90
Total Maintenance	**208.04**	**211.22**	**210.07**	**180.51**	**180.81**	**990.64**
Operations						
Network Operations	12.97	13.50	13.51	13.81	13.99	67.79
Customer Service	33.42	34.82	35.29	36.70	37.85	178.08
Self Insurance Costs	3.30	3.24	3.26	3.40	3.51	16.70
Total Operations	**49.69**	**51.56**	**52.06**	**53.90**	**55.36**	**262.56**
Total OPEX	**257.73**	**262.78**	**262.13**	**234.41**	**236.17**	**1253.20**

All forecast figures are in June 2004 dollars. (millions)

10.4 Consolidated CAPEX Forecasts

Table 10-2: Consolidated Draft Determination CAPEX

	2005/06	2006/07	2007/08	2008/09	2009/10	TOTAL
Asset replacements						
Poles and pole tops	28.516	28.769	28.981	28.701	28.857	143.824
Power and Distribution transformers	16.534	15.599	17.370	17.903	17.448	84.853
Meters	2.694	5.231	5.016	5.873	3.931	22.744
Line conductors	29.538	31.104	32.418	33.627	34.034	160.720
Underground cables	4.644	4.670	3.158	1.800	1.534	15.806
Distribution line and zone substation equipment	25.544	25.126	24.987	25.102	24.734	125.493
Zone substation sites	10.218	9.527	7.245	8.241	11.025	46.256
Control and communication systems	18.299	10.368	12.447	7.009	7.574	55.697
Total Asset replacements	**135.987**	**130.393**	**131.622**	**128.255**	**129.136**	**655.393**
Augmentations						
Transmission	17.973	18.489	25.602	20.143	17.835	100.042
Sub Transmission	12.980	12.761	10.433	5.273	9.465	50.913
Zone Substations	35.033	31.888	31.655	31.208	22.922	152.706
Distribution	39.337	41.609	42.954	44.111	33.480	201.492
Total Corporate Initiated	**105.323**	**104.747**	**110.645**	**100.736**	**83.702**	**505.152**
Customer initiated						
Domestic and Rural	18.666	19.098	19.324	20.051	20.648	97.788
Subdivisions	31.690	32.304	32.931	33.572	34.226	164.723
Public lighting	4.202	4.310	4.372	4.548	4.694	22.126
Meters & Services	12.449	12.769	12.952	13.471	13.907	65.549
Commercial & Industrial	36.301	37.379	38.062	39.744	41.187	192.673
Major Customers	9.410	8.120	6.820	6.820	6.820	37.990
Total Customer Initiated	**112.718**	**113.980**	**114.460**	**118.206**	**121.483**	**580.848**
Reliability Improvement						
Monitoring program	1.544	1.552	1.543	1.574	1.593	7.807
Sub-Transmission	0.000	0.000	0.000	0.000	0.000	0.000
Distribution	0.000	0.000	0.000	0.000	0.000	0.000
Tier (b) expenditure	5.7	5.7	5.7	5.7	5.7	28.4
Tier (c) expenditure	22.7	28.4	23.4	46.9	16.8	138.5
Total Reliability Improvement	**29.944**	**35.652**	**30.643**	**54.174**	**24.093**	**174.707**
System - Other						
Sub-Transmission	0.000	0.000	0.000	0.000	0.000	0.000
Zone Substations	4.644	4.670	4.645	4.736	4.794	23.489
Distribution	3.624	3.644	3.624	3.222	2.495	16.610
Load Energy management	0.355	1.449	1.280	1.348	1.379	5.810
Total System - Other	**8.624**	**9.763**	**9.548**	**9.307**	**8.667**	**45.908**

	2005/06	2006/07	2007/08	2008/09	2009/10	TOTAL
Non-System						
Change Program	22.357	17.500	17.500	17.500	17.500	92.357
Computer Facilities	14.250	8.100	9.100	8.200	7.100	46.750
Vehicles & Mobile Plant	25.000	25.000	25.780	26.265	21.700	123.745
Land & Buildings	12.000	12.000	12.000	12.000	12.000	60.000
Other Fixed Assets	1.179	1.089	0.933	0.933	1.132	5.266
Other Unclassified Acquisitions	1.000	1.000	1.000	2.000	2.000	7.000
Total Non-System	**75.786**	**64.689**	**66.313**	**66.898**	**61.432**	**335.118**
Total CAPEX	**468.381**	**459.224**	**463.232**	**477.575**	**428.513**	**2,296.925**

All forecast figures are in June 2004 dollars. (millions)

Table 10-3: Consolidated Ergon Energy CAPEX Submission

	2005/06	2006/07	2007/08	2008/09	2009/10	Total
Asset replacements						
Poles and pole tops	29.89	30.15	30.37	30.08	30.24	150.724
Power and Distribution transformers	17.18	16.21	18.05	18.61	18.13	88.191
Meters	2.80	5.44	5.21	6.10	4.09	23.640
Line conductors	31.20	32.83	34.19	35.45	35.87	169.530
Underground cables	4.83	4.85	3.28	1.87	1.59	16.428
Distribution line and zone substation equipment	26.80	26.36	26.22	26.34	25.96	131.672
Zone substation sites	10.62	9.90	7.53	8.57	11.46	48.075
Control and communication systems	19.02	10.78	12.94	7.28	7.87	57.888
Total Asset replacements	**142.332**	**136.518**	**137.794**	**134.294**	**135.210**	**686.148**
Augmentations						
Transmission	21.11	36.31	40.33	23.54	22.59	143.878
Sub Transmission	15.92	29.51	24.14	8.29	12.25	90.115
Zone Substations	46.73	68.92	62.59	40.64	33.49	252.368
Distribution	43.70	69.78	69.39	62.19	47.15	292.208
Total Corporate Initiated	**127.463**	**204.509**	**196.446**	**134.662**	**115.488**	**778.568**
Customer initiated						
Domestic and Rural	19.18	19.62	19.86	20.60	21.22	100.484
Commercial & Industrial	37.25	38.36	39.06	40.79	42.27	197.734
Subdivisions	32.65	33.28	33.93	34.59	35.26	169.701
Other projects	-	-	-	-	-	-
Meters & Services	12.72	13.05	13.23	13.76	14.21	66.976
Major Customers	35.74	31.11	25.90	26.04	25.96	144.747
Public lighting	4.30	4.42	4.48	4.66	4.81	22.668
Total Customer Initiated	**141.844**	**139.842**	**136.461**	**140.439**	**143.724**	**702.310**
Reliability Improvement						
Feeder threshold program	7.91	7.91	7.91	7.91	7.91	39.529
Community threshold program	12.12	10.88	13.76	40.35	10.27	87.375
Rising customer expectations program	8.32	31.97	26.30	8.42	6.61	81.614
Monitoring program	2.03	2.08	0.61	1.06	0.71	6.476
MAIFI mitigation program	2.01	3.01	4.51	6.01	4.51	20.057
Total Reliability Improvement	**32.38**	**55.85**	**53.08**	**63.75**	**30.00**	**235.05**

	2005/06	2006/07	2007/08	2008/09	2009/10	Total
System - Other						
Sub-Transmission						
Zone Substations	4.73	4.75	4.73	4.82	4.88	23.909
Distribution	4.08	4.50	4.48	4.28	3.54	20.886
Load Energy management	1.55	2.88	3.02	3.09	3.13	13.672
Total System - Other	**10.358**	**12.139**	**12.232**	**12.191**	**11.546**	**58.466**
Non-System						
Change Program	22.36	17.50	17.50	17.50	17.50	92.357
Computer Facilities	14.25	8.10	9.10	8.20	7.10	46.750
Vehicles & Mobile Plant	25.00	25.00	25.78	26.27	21.70	123.745
Land & Buildings	20.00	15.00	15.00	15.00	15.00	80.000
Other Fixed Assets	1.18	1.09	0.93	0.93	1.13	5.266
Other Unclassified Acquisitions	1.00	1.00	1.00	2.00	2.00	7.000
Total Non-System	**83.79**	**67.69**	**69.31**	**69.90**	**64.43**	**355.12**
Total CAPEX	**538.162**	**616.546**	**605.323**	**555.231**	**500.400**	**2,815.662**

All forecast figures are in June 2004 dollars. (millions)

Table 10-4: Consolidated BRW Forecast CAPEX – Unsmoothed

	2005/06	2006/07	2007/08	2008/09	2009/10	Total
Asset replacements						
Poles and pole tops	29.438	29.987	30.305	30.051	30.218	149.999
Power and Distribution transformers	16.931	16.171	18.004	18.553	18.104	87.763
Meters	2.800	5.384	5.186	6.047	4.107	23.525
Line conductors	30.788	32.685	34.117	35.355	35.774	168.719
Underground cables	4.718	4.777	3.276	1.921	1.656	16.348
Distribution line and zone substation equipment	26.380	26.221	26.174	26.312	25.953	131.039
Zone substation sites	10.434	9.839	7.591	8.595	11.383	47.842
Control and communication systems	18.560	10.743	12.863	7.435	8.005	57.607
Total Asset replacements	**140.049**	**135.807**	**137.517**	**134.269**	**135.199**	**682.842**
Augmentations						
Transmission	21.054	36.144	40.144	23.603	22.237	143.182
Sub Transmission	14.570	21.786	17.875	7.068	11.741	73.040
Zone Substations	39.794	58.917	53.942	36.586	29.739	218.978
Distribution	43.559	68.382	68.085	61.028	46.235	287.288
Total Corporate Initiated	**118.976**	**185.229**	**180.046**	**128.285**	**109.952**	**722.488**
Customer initiated						
Domestic and Rural	18.987	19.560	19.837	20.576	21.178	100.138
Commercial & Industrial	36.903	38.246	39.024	40.729	42.182	197.085
Subdivisions	32.282	33.157	33.877	34.541	35.205	169.063
Other projects	-	-	-	-	-	-
Meters & Services	12.619	13.014	13.223	13.749	14.188	66.793
Major Customers	46.621	38.758	32.552	26.440	21.338	165.709
Public lighting	4.266	4.403	4.475	4.653	4.800	22.598
Total Customer Initiated	**151.679**	**147.139**	**142.989**	**140.689**	**138.891**	**721.386**
Reliability Improvement						
Monitoring program	1.707	1.787	1.803	1.841	1.862	9.000
Sub-Transmission	-	-	-	-	-	-
Distribution	-	-	-	-	-	-
Tier (b) expenditure	5.863	17.706	17.732	5.967	5.969	53.237
Tier (c) expenditure	24.720	32.565	29.895	55.342	22.409	164.930
Total Reliability Improvement	**32.290**	**52.057**	**49.430**	**63.149**	**30.240**	**227.167**
System - Other						
Sub-Transmission	-	-	-	-	-	-
Zone Substations	4.694	4.742	4.725	4.818	4.877	23.855
Distribution	4.057	4.491	4.476	4.275	3.548	20.848
Load Energy management	1.556	2.846	2.992	3.065	3.097	13.557
Total System - Other	**10.307**	**12.079**	**12.194**	**12.157**	**11.522**	**58.259**

	2005/06	2006/07	2007/08	2008/09	2009/10	Total
Non-System						
Change Program	22.357	17.500	17.500	17.500	17.500	92.357
Computer Facilities	14.250	8.100	9.100	8.200	7.100	46.750
Vehicles & Mobile Plant	25.000	25.000	25.780	26.265	21.700	123.745
Land & Buildings	20.500	15.800	15.100	15.000	15.000	81.400
Other Fixed Assets	1.179	1.089	0.933	0.933	1.132	5.266
Other Unclassified Acquisitions	1.000	1.000	1.000	2.000	2.000	7.000
Total Non-System	**84.286**	**68.489**	**69.413**	**69.898**	**64.432**	**356.518**
Total CAPEX	**537.588**	**600.800**	**591.589**	**548.447**	**490.237**	**2,768.660**

All forecast figures are in June 2004 dollars. (millions)

Table 10-5: Consolidated BRW Forecast CAPEX– Smoothed

	2005/06	2006/07	2007/08	2008/09	2009/10	Total
Asset replacements						
Poles and pole tops	27.483	29.289	31.152	31.183	30.892	149.999
Power and Distribution transformers	16.080	17.137	18.227	18.245	18.074	87.763
Meters	4.310	4.594	4.886	4.891	4.845	23.525
Line conductors	30.913	32.945	35.039	35.074	34.747	168.719
Underground cables	2.995	3.192	3.395	3.399	3.367	16.348
Distribution line and zone substation equipment	24.009	25.587	27.214	27.241	26.987	131.039
Zone substation sites	8.766	9.342	9.936	9.946	9.853	47.842
Control and communication systems	10.555	11.249	11.964	11.976	11.864	57.607
Total Asset replacements	**125.113**	**133.335**	**141.812**	**141.954**	**140.628**	**682.842**
Augmentations						
Transmission	26.234	27.958	29.736	29.766	29.488	143.182
Sub Transmission	13.383	14.262	15.169	15.184	15.042	73.040
Zone Substations	40.122	42.759	45.477	45.523	45.098	218.978
Distribution	52.638	56.097	59.664	59.724	59.166	287.288
Total Corporate Initiated	**132.377**	**141.076**	**150.046**	**150.196**	**148.793**	**722.488**
Customer initiated						
Domestic and Rural	18.348	19.553	20.797	20.817	20.623	100.138
Commercial & Industrial	36.111	38.484	40.931	40.971	40.589	197.085
Subdivisions	30.976	33.012	35.111	35.146	34.818	169.063
Other projects	0.000	0.000	0.000	0.000	0.000	-
Meters & Services	12.238	13.042	13.871	13.885	13.756	66.793
Major Customers	30.362	32.357	34.414	34.449	34.127	165.709
Public lighting	4.141	4.413	4.693	4.698	4.654	22.598
Total Customer Initiated	**132.175**	**140.861**	**149.817**	**149.967**	**148.566**	**721.386**
Reliability Improvement						
Monitoring program	1.649	1.757	1.869	1.871	1.854	9.000
Sub-Transmission	0.000	0.000	0.000	0.000	0.000	-
Distribution	0.000	0.000	0.000	0.000	0.000	-
Tier (b) expenditure	9.754	10.395	11.056	11.067	10.964	53.237
Tier (c) expenditure	30.219	32.205	34.253	34.287	33.967	164.930
Total Reliability Improvement	**41.622**	**44.358**	**47.178**	**47.225**	**46.784**	**227.167**
System - Other						
Sub-Transmission	-	-	-	-	-	-
Zone Substations	4.371	4.658	4.954	4.959	4.913	23.855
Distribution	3.820	4.071	4.330	4.334	4.293	20.848
Load Energy management	2.484	2.647	2.815	2.818	2.792	13.557
Total System - Other	**10.674**	**11.376**	**12.099**	**12.111**	**11.998**	**58.259**

	2005/06	2006/07	2007/08	2008/09	2009/10	Total
Non-System						
Change Program	16.922	18.034	19.181	19.200	19.021	92.357
Computer Facilities	8.566	9.129	9.709	9.719	9.628	46.750
Vehicles & Mobile Plant	22.673	24.163	25.699	25.725	25.485	123.745
Land & Buildings	14.914	15.895	16.905	16.922	16.764	81.400
Other Fixed Assets	0.965	1.028	1.094	1.095	1.085	5.266
Other Unclassified Acquisitions	1.283	1.367	1.454	1.455	1.442	7.000
Total Non-System	**65.322**	**69.615**	**74.041**	**74.116**	**73.423**	**356.518**
Total CAPEX	**507.283**	**540.621**	**574.993**	**575.569**	**570.193**	**2,768.660**

All forecast figures are in June 2004 dollars. (millions)