Independent Pricing and Regulatory Tribunal
of New South Wales

Review of Capital and Operating Expenditure of the NSW Electricity Distribution Network Service Providers – Final Report

September 2003

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26 September 2003

Independent Pricing and Regulatory Tribunal of NSW
Level 2
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SYDNEY NSW 2000

REVIEW OF CAPITAL AND OPERATING EXPENDITURES OF NSW DNSPs

We are pleased to submit to the Tribunal our final report on the review of capital and operating expenditures of the New South Wales electricity distribution network service providers (DNSPs) for consideration in the Tribunal's forthcoming price determination.

The main points to come out of the review are outlined in the executive summary that follows the table of contents.

We believe that all representations made by the DNSPs and other stakeholders, including those received last week, have been given full consideration. Our conclusions are based on the material presented to us, the representations made by stakeholders, and our own assessments and judgement. As is normal the report draws distinctions between fact and opinion and dissenting views have been recorded where appropriate to ensure a balanced presentation.

In conclusion we thank you for entrusting us with this important study and for the assistance given at all times.

On behalf of Meritec Limited,
Yours faithfully,

Jeffrey W Wilson
Team Leader

Conrad Holland
Power Systems Engineer

Encl.

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Prepared for the

Independent Pricing and Regulatory Tribunal
of New South Wales

By

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September 2003

ideas change everything

DISCLAIMER

This report reflects the opinions of Meritec Limited and not necessarily those of the Secretariat to IPART or the Tribunal.

It has been prepared on the basis that full disclosure of all data and information that may affect its conclusions has been made to us by the DNSPs. No responsibility is accepted if full disclosure has not been made. Furthermore we do not accept responsibility for any consequential error or defect in our conclusions resulting from any error, omission or inaccuracy in the data or information supplied by the DNSPs, their officers or agents.

Although this report has been provided to IPART on the understanding that it will become a public document it has been prepared solely for IPART as an input into its 2004 determination and not for any other person or for any other purpose. Meritec Limited, its officers, agents, subcontractors and their staff owe no duty of care and accept no liability to any other party, make no representation or warranty as to the accuracy or completeness of the information or opinions set out in the report to any person other than to IPART including any errors or omissions howsoever caused, and do not accept any liability to any party if the report is used for any other purpose.

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Executive Summary

Appointment and Terms of Reference

In December 2002 the Independent Pricing and Regulatory Tribunal of New South Wales (IPART) commissioned Meritec Ltd (Meritec), engineering and management consultants of Auckland New Zealand, to assess: the prudence of each DNSP's operating expenditure (opex) for financial years ending 30 June 1999 (FY 1999) to 30 June 2003 (FY 2003); the prudence of each DNSP's capital expenditure (capex) for the same period; the efficiency of each DNSP's estimates of opex for the period FY 2004-2009; the efficiency of each DNSP's estimates of capex for the period FY 2004-2014; the reasonableness of each DNSP's forecasts of growth in terms of customer numbers, energy sales and maximum demand for the period FY 2004-2009; and the reasonableness of each DNSP's low, medium and high growth scenarios and associated costs.

Meritec, previously known as Worley International Limited, undertook the 1998 capital expenditure review of DNSPs including TransGrid for IPART as part of IPART's 1999 determination and reference is made to the final report of that review in this present report. General principles set out in that report are not repeated here.

Work Programme and Interim Draft Report

Work on the review began in December 2002. A questionnaire and template were prepared in January and were issued to DNSPs for completion after review by IPART. The DNSPs' responses were received in two stages: general information on 28 March and detailed responses on or after 10 April. Meetings were held with the DNSPs during the period 23 April to 1 May. Supplementary information was requested from several DNSPs and was supplied.

We continued with our review of the information during May and June and prepared an interim Draft Report in mid-June for review by IPART, the DNSPs and other stakeholders. The purpose of the report was to set out the status of the work at that time, to summarise the approach adopted, and to present preliminary conclusions for consideration by the DNSPs and non-DNSP stakeholders, thus enabling us to take their views into account. The report concentrated on the key issues affecting the assessment and their likely impact. It did not present detailed findings for individual DNSPs.

Because our analysis was incomplete and because not all information required had been submitted by the DNSPs the interim Draft Report was circulated to DNSPs first, on 25 June, for them to check the accuracy of the statements made before public release of the report. The DNSPs presented detailed and constructive comments by 3 July under considerable time pressure and the comments were incorporated in the report to the extent possible within the available time before the report was released for public comment on 3 July. At the forum on 11 July we presented the report and received further comments from stakeholders attending. Most DNSPs and some non-DNSP stakeholders made written submissions to IPART. These were received on or around 25 July. Further comments were received from non-DNSP stakeholders at a forum held on 17 July.

Further meetings and conference calls were held with the DNSPs during the period 18 July to 29 August and we received further supporting data and revisions to the templates submitted earlier. All outstanding matters were discussed with the DNSPs during this period as we finalised our Draft Final Report.

The Draft Final Report was presented to the DNSPs and IPART for review during the period 4-9 September 2003 and we met again with all DNSPs and IPART on 9-10 September to provide them with a final opportunity to comment on our conclusions. Further detailed written submissions were received from Energy Australia and Integral Energy between 11 and 18 September. These were carefully considered and changes were incorporated where appropriate before the report was tabled in its final form on the date of the accompanying Letter of Transmittal.

The work took longer than anticipated because of the need for more time to absorb the information presented to us and to allow adequate time for consultation.

This Report

This report sets out our final assessment and is presented in ten main sections as follows:

- Section 1 – Introduction (this section)
- Section 2 – Methodology
- Section 3 – General Statistics and Demand Forecasts
- Section 4 – Capital Expenditure
- Section 5 – Operating and Maintenance Expenditure
- Section 6 – Assessment: Energy Australia
- Section 7 – Assessment: Integral Energy
- Section 8 – Assessment: Country Energy
- Section 9 – Assessment: Australian Inland
- Section 10 – Key Issues for the Tribunal.

The appendices include a list of officials met or with whom discussions were held (Appendix A) and a copy of the questionnaire presented to the DNSPs for completion (Appendix B).

Background to the Review

IPART is the jurisdictional regulator for DNSPs in New South Wales under the National Electricity Code (NEC) and regulates network tariffs. In 1999 its determination took the form of a revenue cap but this methodology has been changed for the 2004 determination to a weighted average price cap for distribution with a pass-through of transmission charges and prices for miscellaneous charges and monopoly fees.

The total cost review reported on here is an important input to IPART's determination. As outlined above it includes a review of opex as well as capex. Past expenditures – those since the previous determination – and projected future expenditures are both considered. These tasks required modification of the approach used in the 1998 review that Meritec (Worley International) undertook for IPART as it covered capex alone and did not include a review of a prior period. Specifically, the work includes the assessment of the prudence of actual expenditures in comparison with projected expenditures during the period FY 1999 to FY 2003, and a review of the efficiency of projected future expenditures.

Other changes from the 1998 review include the consideration of different load growth scenarios; the intended preparation of independent load growth projections by the consultant; changes in the scope of potentially excluded services; and the removal of transmission-related costs from IPART's jurisdiction.

Prudence v. Efficiency

A distinction is drawn in the Terms of Reference between the prudence of past expenditures and the efficiency of projected future expenditures. The significance of past capex is that it will be rolled into the asset base until the end of FY 2003 if considered prudent. The review of past opex is undertaken to assist in forming a view of the reasonableness of projected future opex.

We applied our tests in accordance with the definitions of these concepts circulated to the DNSPs by IPART and reported in Section 2 of the main text of the report.

General Approach

The work was undertaken in the following stages although over a longer time than envisaged by IPART:

- Discussion of approach;
- Preparation of questionnaire and its accompanying template;
- Issue of questionnaire and template and receipt of responses;
- Assessments including prudence, benchmarking and efficiency reviews in consultation with the DNSPs;
- Further consultation with the DNSPs and with other interested parties;
- Reporting, first in interim draft form, then in draft form for further review by IPART and the DNSPs, then in final form.

Data requested included but was not limited to:

- General information including annual reports, organisation charts, corporate plans, asset management plans, long-term network development plans, procurement and construction specifications, network performance reports, network line diagrams and maps and other information;
- Information on assets in service including quantities and ages;
- General statistics and performance data;
- Demand forecasts;
- Actual and projected capex and opex;
- Information on inter-company transactions.

Actual and projected expenditures and the timing of major replacement and augmentation programmes and projects were reviewed for reasonableness and optimality to the extent possible.

Age profiles were reviewed but were taken only as a guide of renewal-based capex requirements with more emphasis being placed on asset condition. The DNSPs' asset replacement policies were reviewed for reasonableness and the adequacy of their data was assessed.

For opex, we considered historical trends and cost-based performance indicators and took account of changes in the working environment in the industry. We also took broad account of the quality of each DNSP's asset management practices. We noted any significant movements in opex from year to year, particularly movements coinciding with the change to a new regulatory period, and made such enquiries as we considered necessary to form a view on the prudence or efficiency of the programmes put forward.

As in 1998 we considered the processes and systems used by each DNSP to plan and control its expenditures.

Details are given in the main text of the report.

Benchmarking

Benchmarking was an input into our review. We undertook some analysis ourselves: other evidence was provided by the DNSPs. However, whilst broad comparisons may be made between the DNSPs in NSW and with DNSPs elsewhere, several factors such as those discussed in this report complicate the comparisons. These include differences in types of network, customer and load densities, asset ages and condition, load mixes and other factors including service targets matched to the particular circumstances of each DNSP. We used our experience and judgement in deciding what weight to place on this evidence.

Demand Forecasts

The demand forecasts for each DNSP were reviewed as outlined in Section 3 of the main text. We accepted the overall forecasts as presented by the DNSPs as reasonable for the purpose of our review (in Energy Australia's case the medium scenario) but our opinion on the individual capex projects and programmes put forward relied mainly on local factors.

Capital Expenditure

Our review of capex is presented in Section 4 of the main text. We found no reason to conclude that capex during the period FY 1999-2003 was imprudent. However, we concluded, and recommend to IPART for its consideration, that the overall capex programmes of Energy Australia and Integral Energy for the period FY 2004-2009 be reduced in IPART's modelling for the purpose of its determination to a level that we express as a percentage of current network replacement cost. The main reasons for the proposed reductions were doubts over the methodology used to determine the magnitude and timing of replacement capex (see Sections 2.10, 2.18, 6.3 and 7.3) and a general concern over the magnitude of the capex programmes in aggregate (see Section 2.16). The reductions proposed are as follows: (a) Energy Australia's growth capex projections would be accepted as put forward to us for review (they are equivalent to 1.6% of current network replacement cost as indicated in Table 7) but its projections of capex for other purposes would be reduced from the 2.4% indicated in Table 7 (balance of 4% less 1.6%) to 2.0% expressed as a percentage of current network replacement cost, giving a total percentage of 3.6%; and (b) Integral Energy's growth capex projections would be accepted as put forward to us for review (they are equivalent to 1.7% of current network replacement cost as indicated in Table 7) but its projections of capex for other purposes would be reduced from the 2.8% indicated in Table 7 (balance of 4.5% less 1.7%) to 2.4% expressed as a percentage of current network replacement cost, giving a total percentage of 4.1%. The reduction proposed is equivalent to 10% and 9% for EA and IE respectively.

We did not consider adjustment of the capex projections of Country Energy or Australian Inland necessary.

All capex projections for the period FY 2004-2014 have been presented in FY 2003 dollars but, for the reasons given in Section 4.1 of the main text, it should not in our view be assumed that they will be inflated automatically by IPART for notional increases in construction and installation costs for the purpose of future assessment unless justification is provided.

These recommendations are explained further in the main text.

We understand that should IPART decide to accept these recommendations the DNSPs would not be obliged to spend this amount nor be constrained from spending more; and that responsibility for determining an appropriate prioritisation of expenditure remains with the DNSP concerned as discussed in Section 2.19 of the main text.

Operating and Maintenance Expenditure

Our review of opex is presented in Section 5 of the main text. In reaching our conclusions regarding opex we noted the following principles:

- The principal purpose in reviewing opex during the period FY 1999-2003 was to help determine a reasonable starting level for future opex;
- As with capex, acceptance of the overall level of future opex should have regard to the general factors set out in Section 2 of the main text, particularly Section 2.16;
- Opex should reflect economies of scale;
- Opex should also reflect other pertinent considerations including asset ages noting that aged assets involve more cost than new ones;
- Opex movements over time will reflect changes in the cost of its constituent components – on average 40% labour, 38% overheads, 14% plant and 8% materials;
- The possibility of off-setting savings, as discussed in Section 2.22, should be recognised; and
- The treatment of Y2K- and FRC-related costs should be as set out in Section 2.21.

Our opinion is as follows:

a) We found no reason to conclude that opex during the period FY 1999-2003 was imprudent;
b) We considered the FY 2003 opex figures as agreed with us and presented in the later sections of the report to be a reasonable and balanced starting level in all cases for the determination of future opex in accordance with the recommendations that follow;
c) We saw no reason for opex movements in real terms from FY 2003 onwards to exceed a reasonable allowance for increase in scale of operation, given adequate capital investment;
d) We noted that opex increases were projected to be less than this in the case of some DNSPs;
e) We were not able to quantify possible efficiency gains based on the scope of our work although our work suggested the prospect of some; and
f) We recognised that capex reductions might make it harder for DNSPs to achieve their targets without a corresponding increase in opex.

We recommend for IPART's consideration the following actions in respect of projected opex for the period FY 2004-2009:

i) The implicit re-positioning of Energy Australia's opex not be agreed to;
ii) To give effect to (i) above Energy Australia's opex be adjusted to reflect an increase of no more than 10% in nominal terms from FY 2003 to FY 2009;
iii) Opex for the other DNSPs be accepted as projected;
iv) Before automatically adjusting the projections in future assessments for notional changes in the cost of materials, labour or plant, the cost of opex should be examined to check that DNSPs are maintaining cost-effective operational structures and practices and that their overheads are reasonable.

These recommendations are explained further in the main text.

As in the case of capex we understand that should IPART decide to accept these recommendations the DNSPs would not be obliged to spend this amount nor be constrained from spending more; and that responsibility for determining an appropriate prioritisation of expenditure remains with the DNSP concerned.

Assessments of Individual DNSPs

Individual assessments of the DNSPs are presented in Sections 6 to 9 of the main text.

Key Issues for the Tribunal

In concluding the report we note in Section 10 of the main text the following key issues for the Tribunal's consideration:

Prudence Test of Past Capex

A concern expressed in our interim Draft Report was that, whilst the DNSPs may have set out to manage their programmes in accordance with the capex assumed necessary by the Tribunal, there were significant variations from the projected programmes. Our question at the time was whether this implied a lack of financial discipline or rigour in the sector. We would have expressed the point more accurately if we had used words similar to those chosen by Halcrow in its overview report to IPART of December 2002 on the NSW water agencies. The report noted in this context, correctly in our view, that a test of prudence is softer than a test of efficiency and may reduce the incentive for the regulated agencies to develop robust asset management procedures and deliver capital efficiencies. If all capex that passes a test of prudence is rolled forward automatically into the regulated asset base, the penalty for overspending, including failing to deliver expected capital efficiencies, is largely the cash flow difference in the price path. The shorter the path, the less the incentive. Where over-expenditure is for reasons that should have been foreseeable, the penalty is the same.

The benefits of exceeding expectations on capital efficiency are similarly short-term and give little incentive to out-perform the determination.

Whilst the difficulty of adapting determinations to changing circumstances remains, we would suggest that the Tribunal give further consideration to this issue.

Opex Base

A second point made in the Halcrow report was that the base for opex should not be re-set at every price determination to reflect actual costs. They noted that agencies are sometimes faced with unexpected costs outside their control and that the Tribunal might take a sympathetic view about such expenditures. However, they also noted that where additional expenditure is reasonably foreseeable, a different approach may be appropriate.

Our terms of reference clearly took this point into account as we were asked to examine prior opex with the purpose of assessing a reasonable starting level for future opex. We did, however, face an instance of this type in being asked by Energy Australia to agree to significant increases in its opex over the period, increases that would have had the effect, if agreed to, of re-positioning its opex base. At least, that was our opinion. Our view in that case was that existing and desirable economies should not be done way with. Implicitly we supported Halcrow's point and suggest that it be taken into account by the Tribunal when weighing up our recommendation on the matter.

Future Opex and Capex

Experience shows that infrastructure assets of this type should not be allowed to run down over time. On the other hand our view is that asset lives should be extended for as long as is economic and, where possible, new methods should be found to defer replacement expenditures. A trade-off is needed between replacement capex and opex and we noted that studies are being undertaken in this area by several if not all DNSPs. We noted also that modern equipment is generally designed to be as free of maintenance as possible in recognition of the high cost of labour in developed countries. Further work would be desirable on a study of economic asset lives in the sector in this context.

Acknowledgements

The willing co-operation and assistance of the DNSPs' management and staff during the course of the review is gratefully acknowledged especially in light of the tight time frames for their responses. The willing cooperation and assistance of IPART is gratefully acknowledged including their forbearance when the conclusion of the work was delayed. The assistance and contributions of other stakeholders is also acknowledged with thanks.

1.0 Introduction

1.1 Appointment and Terms of Reference

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1.2 Work Programme and Interim Draft Report

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The Draft Final Report was presented to the DNSPs and IPART for review during the period 4-9 September 2003 and we met again with all DNSPs and IPART on 9-10 September to provide them with a final opportunity to comment on our conclusions. Further detailed written submissions were received from them between 11 and 18 September. These were carefully considered and changes were incorporated where appropriate before the report was tabled in its final form on the date of the accompanying Letter of Transmittal.

The work took longer than anticipated because of the need for more time to absorb the information presented to us and to allow adequate time for consultation.

Our work was carried out by a team led by Jeffrey Wilson. Other team members involved were Michael Whaley, Power Economist, Conrad Holland, Distribution Engineer, Dave Almond, Power Engineer and other technical staff.

1.3 This Report

This report sets out our final assessment and is presented in ten main sections as follows:

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The appendices include a list of officials met or with whom discussions were held (Appendix A) and a copy of the questionnaire presented to the DNSPs for completion (Appendix B).

1.4 Material Not Reproduced

Many thousands of pages of supporting material were received from the DNSPs during the course of the study together with written representations from some non-DNSP stakeholders. This material has been summarised or reproduced in this report to the extent necessary to explain our conclusions or to enable IPART to conclude its determination. Detailed submissions presented to us by the DNSPs comprised their completed questionnaires and templates, internal documents, detailed expenditure projections and other supporting material and are considered confidential to IPART and the DNSPs concerned.

1.5 Independence

Several DNSPs provided us with copies of independent assessments they had commissioned on aspects of their cases. These assisted us and we were guided by them but did not consider ourselves bound by the conclusions expressed by the other parties.

Some non-DNSP stakeholders made representations to us on the factors that they thought we should consider or the conclusions we should reach. Again we were guided by their representations but did not consider ourselves bound by them.

IPART provided guidance in respect of our terms of reference and assisted us in our work.

We gave full consideration to all representations made but are satisfied that none influenced our conclusions inappropriately.

1.6 Abbreviations

The following abbreviations are used throughout this report when referring to the DNSPs: AI for Australian Inland, CE for Country Energy, EA for Energy Australia and IE for Integral Energy.

"n.a." in the tables means 'not applicable'; "d.n.s." means the DNSP concerned did not submit the data and we were not able to estimate it; and "c." means circa or 'about'. Sums have generally been rounded.

FY 2003 means the financial year ending 30 June 2003 etc.

1.7 Acknowledgements

The willing co-operation and assistance of the DNSPs' management and staff during the course of the review is gratefully acknowledged especially in light of the tight time frames for their responses. The willing cooperation and assistance of IPART is gratefully acknowledged including their forbearance when the conclusion of the work was delayed. The assistance and contributions of other stakeholders is also acknowledged with thanks.

1.8 Disclaimer

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2.0 Methodology

2.1 Background to the Review

IPART is the jurisdictional regulator for DNSPs in New South Wales under the National Electricity Code (NEC) and regulates network tariffs. In 1999 its determination took the form of a revenue cap but this methodology has been changed for the 2004 determination to a weighted average price cap for distribution with a pass-through of transmission charges and prices for miscellaneous charges and monopoly fees.

The total cost review reported on here is an important input to IPART's determination. As already outlined in Section 1.1 it includes a review of opex as well as capex. Past expenditures – those since the previous determination – and projected future expenditures are both considered. These tasks required modification of the approach used in the 1998 review that Meritec (Worley International) undertook for IPART as it covered capex alone and did not include a review of a prior period. Specifically, the work includes the assessment of the prudence of actual expenditures in comparison with projected expenditures during the period FY 1999 to FY 2003, and a review of the efficiency of projected future expenditures.

Other changes from the 1998 review include the consideration of different load growth scenarios; the intended preparation of independent load growth projections by the consultant; changes in the scope of potentially excluded services; and the removal of transmission-related costs from IPART's jurisdiction.

2.2 Prudence v. Efficiency

A distinction is drawn in the Terms of Reference between the prudence of past expenditures and the efficiency of projected future expenditures. The significance of past capex is that it will be rolled into the asset base until the end of FY 2003 if considered prudent. The review of past opex is undertaken to assist in forming a view of the reasonableness of projected future opex.

IPART advised the DNSPs in November 2001 that for capex to be judged prudent the expenditure option and its timing should be consistent with good industry practice given:

- current and projected capacity;
- current condition of assets and renewal requirements;
- alternatives of contracting for support through demand management and distributed generation (taking into account emerging trends in technology and costs);
- current safety standards for the distribution network and accepted planning standards;

- current and foreseeable policies in regard to factors such as environmental requirements and contestability;
- current demand and reasonable projections for demand; and
- analysis of the risks attached to the above elements.

IPART also noted at that time that past experience with prudence tests highlighted that such tests start from an assessment of the quality of, and commitment to, planning and evaluation procedures of the DNSP. It expressed the view that a benchmark for that was 'best practice' within the industry for the planning, provision and utilisation of assets and service standards and that it included the integration of these processes with pricing strategies and 'market testing' for alternatives. It went on to note that issues that could be addressed in further guidance to the DNSPs on prudence tests could include: appropriate methodologies for evaluating DNSP capex, e.g. least-cost analysis, cost-benefit analysis or market benefit analysis; the extent and nature of market testing through pricing, expressions of interest or standard offers to determine the feasibility of non-network options; the relationship between capex and service quality or reliability; the incorporation of environment obligations and externalities; the treatment and valuation of changes in losses.

IPART noted that efficient expenditure, on the other hand, means that opex and capex, considered together, are or are projected to be the least-cost way of providing the requisite network services over the life of the network.

We applied our tests in accordance with these concepts. Efficiency was tested by considering the expenditures in accordance with accepted power planning concepts, risk analysis and operational practice: prudence was considered in respect of prior expenditures only, modifying the efficiency approach based on our understanding of the information available at the time and taking account of the particular points noted by IPART above.

2.3 General Approach

The work was undertaken in the following stages although over a longer time than envisaged by IPART:

- Discussion of approach;
- Preparation of questionnaire and its accompanying template;
- Issue of questionnaire and template and receipt of responses;
- Assessments including prudence, benchmarking and efficiency reviews in consultation with the DNSPs;
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Data requested included but was not limited to:

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Age profiles were reviewed but were taken only as a guide of renewal-based capex requirements with more emphasis being placed on asset condition. The DNSPs' asset replacement policies were reviewed for reasonableness and the adequacy of their data was assessed.

For opex, we considered historical trends and cost-based performance indicators and took account of changes in the working environment in the industry. We also took broad account of the quality of each DNSP's asset management practices. We noted any significant movements in opex from year to year, particularly movements coinciding with the change to a new regulatory period, and made such enquiries as we considered necessary to form a view on the prudence or efficiency of the programmes put forward.

As in 1998 we considered the processes and systems used by each DNSP to plan and control its expenditures.

Details are given in later sections of the report.

2.4 Data Used

Unless noted otherwise the report is based on the questionnaires and templates completed by the DNSPs and submitted to us, including agreed corrections and adjustments to the templates, and the documents submitted in response to Section 2 of the questionnaire. Where information was not submitted in response to specific questions we were able, in some cases, to deduce it from responses to other questions. Where necessary and where appropriate, we estimated it. Where we made corrections or adjustments we have generally indicated this in the text.[1]

[1] EA subsequently advised us that its actual FY 2003 opex differed from the estimates included in its template but, by then, we had concluded our analysis using the template data.

2.5 Benchmarking

Benchmarking was an input into our review. We undertook some analysis ourselves: other evidence was provided by the DNSPs. However, whilst broad comparisons may be made between the DNSPs in NSW and with DNSPs elsewhere, several factors such as those discussed in this report complicate the comparisons. These include differences in types of network, customer and load densities, asset ages and condition, load mixes and other factors including service targets matched to the particular circumstances of each DNSP. We used our experience and judgement in deciding what weight to place on this evidence.

2.6 Network Planning Criteria

All DNSPs with the exception of AI have documented network planning criteria including security of supply criteria, permissible voltage limits and permissible plant loading guidelines (AI's criteria are being redeveloped). The security of supply criteria generally included a mix of deterministic and probabilistic criteria applied in accordance with current international practice. Voltage limits generally included normal and emergency thresholds. These and the plant loading guides were found generally to be consistent with accepted international practice and published Australian or international standards and we considered them generally suitable for the particular networks concerned. Reference in this context to international practice is generally to Cigré and CIRED publications particularly the findings of Cigré/CIRED Working Group CC.01 (Cigré 37.07-CIRED 6) published in October 1995, the *Summary on planning methods for sub-transmission systems* prepared by the same working group and published in *Electra No 138* in 1991, and the considerable body of publications and papers on this subject describing the planning criteria used in the UK, Europe, North America and Australasia as well as other regions.[2] [3]

2.7 Capex Approval Processes

All DNSPs with the exception of AI documented their internal controls used to monitor capex.[4] The controls generally included: (a) establishing the need for action; (b) establishing consistency with the organisation's corporate objectives and long-term network development plans; (c) determining the least-cost solution; and (d) determining

[2] We reviewed this material as part of a comprehensive international comparison of distribution and transmission system design carried out between 1998 and 2003 for *Rede Eléctrica Nacional S.A.* of Portugal and others. The comparison formed part of a study of the optimal dimensioning of the power network in that country.

[3] Network planning standards in Australia are developed voluntarily by the DNSPs generally in accordance with prevailing international practice.

[4] AI's Asset Management Plan and Long-Term Network Development Plan included information on these procedures but in limited detail.

the rate of return on investment. The most important items as far as this review is concerned were the establishment of need, the determination of optimal timing of the resulting works, and compliance with the DNSPs' licence conditions to investigate demand management alternatives in certain circumstances. We did not consider the achievement of a rate of return on investment equal to or in excess of the weighted average cost of capital (WACC) as the ruling criterion where need was established under other criteria as, in low-growth and low-loss situations such as those prevailing in the State, a lower rate of return may say more about tariffs than about the merit of particular works.

A detailed review of all projects for compliance with the network planning criteria and capital approval processes was beyond the scope of this review so we limited ourselves to the question of how the stated criteria and processes had affected capex, made or projected, as best we were able to tell. We considered, in general, whether:

- Network modelling had been used to assess the capacity of the system;
- Account had been taken of load transfer capability between substations and through lower voltage networks where available;
- The security of supply criteria used, if deterministic (e.g. n-1) in the first instance, had been supplemented by a probabilistic analysis;
- Non-network solutions had been considered;
- The timing of the work appeared reasonable.

We noted that some DNSPs had had their projections reviewed independently but we did not consider ourselves bound by the findings of those assessments.

We noted that whilst the particular items of work might be justified the optimality of their timing was difficult to gauge.

We also noted that DNSPs were required to have their responses signed by their directors.

2.8 Installed Cost of New Assets

DNSPs were asked in the 1998 capex review to indicate whether their cost estimates assumed unit rates similar to or the same as those in the then reasonably new Treasury Guidelines on valuation. The same question was asked again this time. In both cases, more so this time, most DNSPs said that their expenditure projections were based on their own estimates of cost to complete new works rather than on the Guidelines although CE said it used the Guideline replacement costs for its projections. We carried out a high-level review of the DNSP's cost estimates to determine their reasonableness noting that, in most cases, a considerable volume of the work undertaken was bid competitively. We accepted the inclusion of contingencies in the estimates in accordance with normal practice. Details are presented in later sections of the report.

2.9 Optimality of Design and Construction Practices

We discussed with the DNSPs their design and construction practices to form a general view on their optimality (in AI's case the adoption of designs from another DNSP is under consideration) and considered them reasonable for the purpose of this review.

2.10 Asset Renewal Expenditure

We noted that all DNSPs had conventional asset renewal and replacement policies that recognised the need for judgement when determining whether replacement is preferred to refurbishment or maintenance. All recognised that age alone does not determine need although their replacement capex naturally reflects the age profiles of their assets.[5] Some used computer models to predict or check future replacement capex requirements although as always the level of confidence placed in such findings is dependent on the confidence attached to the input parameters assumed.

Most DNSPs confirmed that their condition assessment programmes had been expanded in the mid-1990s, probably in response to growing commercial pressures in the industry at that time and a desire to improve service quality. They outlined their programmes and we satisfied ourselves of their general appropriateness and scope. A review of the results of the programmes was beyond the scope of our work but we were satisfied that the DNSPs had broad justification for their requested replacement capex projections in terms of their nature and in some instances urgency. We were not able to judge with certainty the proposed timing of the components or the optimality of the implicit capex-opex trade-offs.

2.11 Renewals for Environmental and Other Reasons

The same or similar environmental, safety and statutory obligations affecting future capex were identified by all DNSPs, namely: environmental protection, occupational health and safety, fire mitigation, site security, etc. The only local government impact cited was a general requirement to service new urban residential developments underground in many urban areas. Expenditure under this category generally comprised only a small part of the total.

[5] Guidance on standard lives can be obtained from published papers, including the NSW Treasury's draft policy Guidelines on valuation, and from industry experience. Generally we consider that the lives given in the Guidelines are reasonable for valuation purposes but actual lives may exceed the Guidelines' standard lives in some instances. Emphasis in the 1990s on the restructuring, valuation, sale and purchase of DNSPs worldwide brought asset lives into sharper focus and the accompanying drive for cost efficiencies in the industry resulted in considerable emphasis being placed on improved asset management and on the achievement of life extensions where economic.

2.12 Demand-Related Expenditure

The prediction of growth (demand-related) capex requires knowledge of future demand and load patterns generally and in each particular part of the network separately. We reviewed the DNSPs' overall demand forecasts and received in some cases independent reports on them. We were satisfied that the forecasts were reasonable. Most DNSPs provided data on loads at the zone substation level and we were able to refer to it when reviewing selected capex projects from their programmes. We concluded that there was, in general, justification for the growth-related works proposed although the optimality of their timing was not always clear.

2.13 Reliability and Quality Improvement

We reviewed the DNSPs' past and projected capex related to reliability and quality improvement. In some instances no expenditure was recorded under this heading for network assets as the expenditures were ascribed principally to replacement or growth. We noted that some DNSPs had included expenditure for under-frequency load-shedding equipment to meet NEC requirements and for power factor correction programmes.

We considered what link we would expect to discern between expenditure on reliability improvement and outcomes in terms of improvement in network performance indices. We concluded that the link might be difficult to discern because of the problems associated with segregating expenditures that have a direct impact on reliability improvement from other expenditures and because SAIDI, SAIFI and CAIDI and the other reliability indicators in use are 'lagging' indicators. By this we mean that they tend to reflect past practice and its resulting network condition rather than current practice and consequential future condition. They are also influenced by the way in which the DNSPs are managed and by factors outside their control including but not limited to weather. An added complication is that present trends in reliability of supply in the NSW DNSPs are mixed. [6]

For the purpose of the review we accepted that reliability targets similar to or the same as present levels of reliability were, prima facie, reasonable and we decided not to adopt scenarios based on alternative service levels or risk as the basis of our assessment.

2.14 Demand Management and Non-Network Solutions

Noting that DNSPs have for many years used ripple control systems, time clocks and in some cases special tariffs for interruptible loads to manage their peak loads we asked all DNSPs to indicate the magnitude of controlled load and to answer questions about their past and current load management policies and practices. Since future load may be reduced by additional demand management programmes and since capex may be

[6] This is not to say that there is no link but only that it is difficult to quantify.

deferred or reduced by the use of non-network solutions we also asked the DNSPs for information on their current programmes. We looked for pro-active responses and a commitment to the programmes.

All DNSPs recognise their current obligations to investigate non-network solutions in certain circumstances but none reported prospects for its short-term implementation that were material in terms of their impact on the total capex programmes foreseen. However, whilst the impact of these programmes in the current and forthcoming regulatory period appears to be minimal it is an area that requires more emphasis by DNSPs in the future to ensure that worth-while prospects are identified and actioned.

2.15 Capex Projections

As is normal we found that capex projects planned for implementation in the immediate future had generally been prepared in more detail than those planned for later in the period with the latter often not yet fully designed or tested against the requisite investment criteria. Increases in actual growth from forecast figures are normally accommodated at the distribution level by advancing the implementation of capital works that form part of the long-term network development plan. Conversely, slower-than-expected load growth is accommodated by deferral. It is normally considered prudent to maintain a reserve against unexpected increases in demand in the short term using risk assessments to judge how much load is 'at risk' from plant failure or sudden and unexpected load increases and an accompanying loss of security of supply. Our determination of reasonableness combined with prudence in respect of past capex, or reasonableness combined with efficiency in respect of future capex, was made in this context. We considered that the level of preparation of the projects and programmes we reviewed was generally appropriate for planning purposes recognising that plans do not constitute, by themselves, a justification for proceeding with work until detailed studies have been prepared and the relevant criteria met.

2.16 Reasonableness of Aggregate Expenditure Projections

Although each individual capex project and programme may be justified when taken in isolation it is still necessary that the capex projections overall should be reasonable in total. Reasonable in this context should relate not only to the network itself – with allowances for replacement plus growth, for example – but also to the financial position of the DNSPs and any relevant economic considerations such as those arising through the impact of possible tariff increases. Consideration should also be given to any perceived approaching wave of asset replacement expenditure generated by an ageing asset base but the emphasis given to this factor should be muted by the ability to keep assets in service longer when needed, albeit at the cost of additional opex and possibly additional risk. We considered the reasonableness of the overall programmes in light of network condition, projected growth, magnitude in relation to the replacement cost of the network, and the representations made to us by the DNSPs.[7] [8]

2.17 Opex Projections

Our approach to opex was to review the level of past and projected expenditures in relation to the current replacement value of the asset base and to review the patterns of expenditure for consistency. We examined any material variations in the level of opex from FY 1999-2009. Cost-based performance indicators were defined and calculated by the DNSPs in accordance with our instructions and other benchmarking information provided by the DNSPs was taken into account as already mentioned in Section 2.5. Details of our findings are given in the later sections of the report taking into account all relevant factors including the general principles set out in Section 2.16 above.

2.18 Trade-Off between Capex and Opex

We reviewed the DNSPs' assessments of the trade-off between opex and capex and noted that various methodologies had been developed to help determine an optimal balance between the two. We noted as already mentioned in Section 2.10 that the confidence placed in the outcomes of the modelling is dependent on the confidence attached to the input parameters assumed. There remained in our view a need for the accumulation of more operational data to fully test the conclusions reached in the modelling. We noted, too, that criteria for replacement, where defined, were of necessity arbitrary to some extent and might have had the effect of precipitating replacement capex prematurely.

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[7] Some DNSPs asserted that if the various components were considered acceptable the aggregate should also be considered acceptable. We did not accept this view since the sum of the parts does not necessarily add to a reasonable and balanced whole.

[8] Some DNSPs considered that we should have documented our analysis in similar detail to their own before reaching conclusions in respect of the reasonableness of their aggregate expenditures but we did not accept that view either. We did not feel constrained by their argument as we formulated our opinions based not only on our own judgement and experience but also with the advantage of having reviewed the DNSP's comprehensive submissions and heard their explanations.

2.19 Prioritisation and Risk

Some DNSPs and IPART asked whether we could or would express a view on whether, if capex, opex or both were curtailed, there would be an impact on service delivery standards and we noted that Section 2.13 above responds to the point.

Some DNSPs asked whether we would express the view that a reduction in capex implied the need for additional opex to maintain older assets that otherwise would be replaced. We noted that the linkage may exist in certain circumstances but we did not consider it appropriate to express a firmer view on it here since the impact of changes in expenditure will depend amongst other things on how the DNSPs are managed. It is the prerogative of the DNSPs' owners to decide the risks that should be borne and to decide the prioritisation of expenditure should IPART's determination assume a reduction in expenditures.

2.20 Expenditures for Possibly Excluded Services

We requested details of expenditures for possibly excluded services as now defined, including customer capital contribution works, metering, public lighting and some other services, to see the full expenditure picture. Some DNSPs considered that customer capital contribution works should have been left out of the review since they are costs over which the DNSP may have no control. The required information was, however, provided and was analysed as we were required to do. We did not see any reason to query the estimates for customer capital contribution or developer contribution works; and expenditures on metering and public lighting appeared reasonable. Details are given for each DNSP separately in the later sections of the report.

2.21 Other Expenditures (Y2K and FRC)

Expenditures on Y2K and costs associated with full retail contestability (FRC) are reported separately in the later sections of the report. Prior expenditures on FRC had already been assessed by others for IPART and agreed to the extent considered appropriate by IPART. The costs already accepted by IPART were not reviewed again. FRC-related costs not previously accepted had, as far as we could tell, been turned down on the ground that they were not incremental – in other words, they were not needed exclusively for FRC – and we thus formed the view in consultation with IPART that their prudence be considered as part of total capex and opex for regulated services. Details are discussed for each DNSP separately in the later sections of the report.

Prior expenditures on Y2K have not been accepted by IPART to date. Our view is that they should have been, and apparently were, absorbed within the total opex figure without separate provision for their recovery and we maintained this approach when we assessed opex for overall reasonableness. IPART may, however, consider that there are other reasons for accepting the expenditures for recovery.

2.22 Opex and the Off-Setting Effect of Savings

As with capex, opex projections must be assessed for reasonableness overall, irrespective of the justification of their constituent parts when taken in isolation. Implicit in this, in our view, is the presumption that unexpected costs or increased expenses should be off-set to the extent possible by efficiency improvements or savings in other areas. DNSPs should not in our view be exempt from the pressures that require companies in other sectors of the economy to absorb new costs to the extent possible in competitive markets rather than passing their business risk to customers.

We discuss the reasonableness of the overall opex projections separately for each DNSP in later sections of the report.

3.0 General Statistics and Demand Forecasts

3.1 Statistics

Table 1 below presents general statistics of the DNSPs for FY 2003.

Table 1: General Statistics of the DNSPs

	AI	CE	EA	IE
Total service area (sq km)	155,100	582,000	22,275	24,500
Total system length (km)	9,425	182,023	c.47,144	33,863
Percent of total system length underground (%)	< ½	2	26	27
Maximum demand (MW)	c.77	1,990	5,051	3,190
Energy sold (GWh)	414	10,134	25,738	16,641
Annual load factor (%)	c.61	57	61	64
Employee Numbers (full-time equivalent, year-end):				
Network	74	2008	c.2,737	1,547
Retail	17	199	c.395	235
Non-regulated business	112	551	c.395	264
Total	203	2,758	c.3527	2,046
Customers:				
Customers connected (No)	19,066	726,333	1,478,600	800,807
Customer density (customers per km of system length)	2	4	31	24
Customer density (customers per sq km of service area)	0.12	1.2	66	33
Customers per employee (network)	258	362	c.540	391

The table highlights the differences between the DNSPs in terms of scale of operation, service area, load density and customer density. The table itself is a generalisation as individual DNSPs are not homogeneous.

Asset utilisation and investment in each DNSP in FY 2003 is summarised in Table 2 below. We would have preferred the DNSPs who did not provide all the data to have done so but we accepted AI's statement that it did not have adequate metering or up-to-date network analyses available to provide all the information requested (it did provide a table of zone substation capacity utilisation). It accepts that it should have.

The table demonstrates that DNSPs with large urban concentrations have the highest asset utilisation, lowest cost per unit of demand served and lowest losses.

Table 2: Asset Utilisation and Investment

	AI	CE	EA	IE
Network Utilisation:				
Overall power transformer capacity (Nameplate MVA)	155	7,718	16,375	10,347
Corresponding utilisation ratio (%)	58	27	31	34
Substations transforming to an intermediate voltage level:				
Total load transferred through these substations (MVA)	d.n.s.	d.n.s.	c.4,047	2,801
(n-1) nameplate capacity of transformers (MVA)	25	297	c.4,420	2,787
Corresponding utilisation (%)	d.n.s.	d.n.s.	c.92	100
Substations transforming to distribution voltage:				
Total load transferred through these substations (MVA)	d.n.s.	2,095	c.5,598	3,071
(n-1) nameplate capacity of transformers (MVA)	70	3,265	c.6,260	3,300
Corresponding utilisation (%)	d.n.s.	64	c.90	93
Distribution substations:				
Total system MD less HV customer demand (MVA)	61	2,488	d.n.s.	5,334
Distribution transformer capacity (MVA)	208	6,769	d.n.s.	7,620
Utilisation ratio (%)	29	37	d.n.s.	70
Network Investment:				
Total network investment at replacement cost ($ m)	260	7,909	c.10,927	c.6,208
Corresponding investment per MVA of MD ($ 000 / MVA)	2,902	3,179	c.2,192	c.1,933
Total network investment at DRC	168	3,733	c.4,698	c.3,382
Corresponding investment per MVA of MD ($ 000 / MVA)	1,873	1,501	c.942	c.1,084
Energy Losses				
Energy losses as percentage of energy entering the system	10.5% a/	9.5%	4.7%	5.5%

a/ Relates to AI's load excluding its largest CRNP customer. Including it, overall losses were 6.5%.

SAIDI minutes lost in FY 2002 are shown in Table 3 below and the numbers of faults per 100 km of overhead circuit are shown in Table 4. The reliability data in Table 3 is not sufficiently comprehensive to comment on but the line fault data presented in Table 4 is indicative of reasonable performance except that EA's 66 kV line fault incidence appears high. As already mentioned in Section 2.13 present trends in reliability are mixed.

Table 3: SAIDI Minutes Lost in FY 2002

	AI	CE	EA	IE
Total Urban – all causes except planned	d.n.s.	116	d.n.s.	45
Total Rural – all causes except planned	d.n.s.	281	d.n.s.	55
Total – all causes	359	178	98	134
Total excluding loss of bulk supply	d.n.s.	178	98	134

Table 4: Faults per 100 km of overhead circuit in FY 2002

	AI	CE	EA	IE
132 kV overhead lines	n.a.	n.a.	5.4	2.9
66 kV overhead lines	2.2	2.6	48.3	8.2
33 kV overhead lines	1.3	14.8	30.2	19.8
22/11 kV overhead lines	10.0	14.2	38.7	58.7
SWER overhead lines	1.3	2.3	6.8	n.a.
LV overhead lines	68.1	13.9	8.1	6.5

3.2 Forecast Demand

Table 5 shows average actual growth rates over the period FY 1999-2003, forecast growth rates for the period FY 2004-2014, the magnitude of controlled load and the DNSPs' assessments of the impact of current non-network solutions on their networks.

Table 5: Growth in Demand

	AI	CE	EA	IE
Actual growth in energy sales, FY 1999-2003, p.a.	0 a/	1.7%	2.7-3.2%	1.4% d/
Projected growth in energy sales, FY 2004-2014, p.a.	1.6% b/	1.7%	0.9-2.2% c/	2.1%
Projected movement in annual load factor	Unknown	decreasing	Decreasing	decreasing
Estimated total controlled load in FY 2003 (MW)	d.n.s.	1,500	1,400	1,556
Impact of distributed generation and other non-network solutions currently in service e/	Not material	Not material	Not material	Not material

a/ 1.5% excluding largest CRNP customer. See text below.
b/ See text below.
c/ 1.6% for EA's medium growth scenario.
d/ This figure is taken from IE's template.
e/ Reference to materiality is to overall capex.

Points noted were:

- Several DNSPs prepared alternative growth scenarios but only EA carried different growth rates into the expenditure templates sent to us;[9]
- All growth rates were and are projected to remain modest overall but it is growth in localised areas that precipitates a need for capex;
- IE presented a 'reduced risk' scenario for its capex but assumed the same growth rate;
- IE projected the highest average annual growth rate at 2.1%;

[9] EA gave alternative rates of growth for FY 2003 as well: hence the range reported by it under the heading "actual growth in sales FY 1999-2003".

- AI reported no projected growth overall during the period FY 1999-2003 but experienced 1.5% growth excluding its largest CRNP customer (the customer accounts for around 30% of total energy sales). It projects a growth of 2.25% p.a. during the period FY 2004-2009 excluding the same customer;
- CE, EA and IE reported that their forecasts had been reviewed independently or that they had commissioned independent input into the forecasting assumptions. They gave us copies of the reports;
- The impact of demand management measures already in service or planned is taken into account in the projections;
- Growth is not evenly spread across the service areas;
- Forecasts for individual substations were generally based on local factors and, in some cases, as is normal, varied significantly from the average growth rates.

The demand forecasts for each DNSP are discussed further in later sections of the report. For the purpose of our review we accepted the overall forecasts as summarised above as reasonable (in EA's case the medium growth scenario) but our opinion on the individual capex projects and programmes put forward relied mainly on local factors.

Most if not all DNSPs emphasised the impact that higher growth rates would have on their capex needs should growth be more rapid but we noted that our work is based on the 'most likely' scenarios as presented to us and endorsed by the independent reports – the 'medium' scenario in each case. It goes without saying that actual growth rates may be different from those forecasts.

4.0 Capital Expenditure

4.1 Capex in FY 1999-2003

All DNSPs expended capital over the period FY 1999-2003 in excess of their projections made at the time of the 1998 capex review. Amounts projected and spent are summarised in Table 6 below. In some cases the projections approved by IPART in its 1999 determination differed from the projections made by the DNSPs in 1998 but the comparison here is presented initially in terms of the DNSPs' own wishes as expressed at the time without adjustment except in one case, CE. We took account of changes in the projections of CE's pre-merger entities made during 1999 after completion of our 1998 capex review since the changes were reviewed and approved by us and accepted by IPART prior to its determination of December 1999.

The projections are presented in 1998 dollars and actual expenditures are presented in nominal terms. DNSPs were asked to indicate the additional costs that arose through increases in construction rates and several reported a nil impact. This may have been attributable in some cases to the assumption that we would adjust the projections for movements in the consumer price index automatically – CPI is not, in our opinion, a suitable index for the purpose – or another index related to the cost of manufactured electrical goods, construction-related activities, skilled labour or a combination of these factors.[10] In the absence of quantitative evidence of cost increases from some DNSPs, and in light of the statement of one DNSP that that construction cost increases had not been material, we considered that adjustment was not appropriate. In short, we saw no need to recognise possible additional costs where none may have arisen.

EA's figures exclude its transmission expenditures: no other DNSPs have transmission assets.[11]

Initially, the data received contained errors and inconsistencies as reported in our interim Draft Report but adjustments were made by the DNSPs to remove these completely as far as we are able to tell.

In some instances expenditures had had to be re-categorised to fit historical or projected data into the reporting categories we requested. For example AI projected zero

[10] The indexation of capital costs for network equipment and related assets, if applied, should be based on procurement by international competitive bidding and competitive pricing for installation work including its constituent elements – materials (imported and locally manufactured), plant and labour – and overheads should be checked for reasonableness. Adjustment of the cost of imported manufactured goods for movements in currency exchange rates might be needed and market fluctuations would need to be taken into account. The adjustment may need to be tied also to commodity prices, particularly the price of copper and aluminium. Some items may decrease in cost over the period due to technological change or increased competition. For example electricity utilities elsewhere are benefiting from a reduction in the cost of large transformers purchased by international competitive bidding.

[11] The definition of transmission assets is in accordance with category T1. The specific assets treated as transmission assets are, EA informed us, those identified as such in Erlunda Associates' report of May 2003 plus additional assets on the Central Coast as advised to IPART and us in July 2003.

expenditure under the 'environmental and other' heading but reported expenditures for that purpose; and CE projected expenditures under the 'reliability improvement' heading but reported nil expenditure. The assistance of the DNSPs in correcting errors and resolving inconsistencies put the analysis on a sound footing. We acknowledge their assistance during this period.[12]

Table 6: Projected v. Actual Capex FY 1999-2003

	AI	CE	EA	IE
Projected renewal capex – end of life($m)	<1	237	219	189
Actual ($m)	<1	303	196	107
Projected renewal capex – environmental etc ($m)	0	0 a/	21	1
Actual ($m)	6	0	55	14
Projected non-network capex ($m)	0	134	97	44
Actual ($m)	3	206	144	187
Projected total renewal capex ($m)	<1	371	337	233
Actual ($m)	10	509	395	308
Projected growth capex ($m)	5	213	228	133
Actual ($m)	3	258	596	244
Projected reliability improvement capex ($m)	2	84	68	5
Actual ($m)	3	0 b/	50	12
Projected capex – possibly excluded services ($m)	8	117 b/	54 c/	66 c/
Actual ($m)	5	213	271	187
Projected capex – Y2K and FRC ($m)	0	0	0	0
Actual ($m)	<1	22	71	28
Projected capex – total ($m)	15	784	687	437
Actual – total ($m)	21	1,002	1,383	778
Actual as pct of projected	137%	128%	202%	178%
Actual as pct of projected if capital contribution works, Y2K and FRC capex are deducted	191% d/	113%	164%	142%

Figures have been rounded.
a/ Included with renewal capex.
b/ Around ¾ of this item are comprised of capital contribution works: the remainder is metering and public lighting.
c/ The projections for these items excluded any budget for capital contribution works but actual costs were significant. See the later tables in the report for details.
d/ This increased percentage reflects an under-run in capital contribution works.

Variances between the projections and actual expenditures did not exhibit common themes except that:

[12] The principal reasons for changes from the figures in our interim Draft Report were the removal of transmission-related expenditures from EA's data, the elimination of double-counting in several cases, and the incorporation in the projections of the adjustments made in CE's figures and reported above.

- Overruns in non-network expenditure are notable and common to all DNSPs (for reasons that are not clear to us AI did not include a budget in its projections for non-network items at all and CE said its was less than it wanted although the other DNSPs apparently did include budgets to the extent that they wished: perhaps neither the 1998 cost review nor the 1999 determination gave adequate recognition to this cost component of the businesses; and perhaps in some cases the DNSPs themselves did not take sufficient care when projecting their costs in this area);
- ‘Possibly excluded services’ as currently defined – its biggest component is customer capital contribution works – do not appear to have been well budgeted in 1998 and generally overran (expenditures on customer capital contribution works were clearly not projected adequately);
- Some projections were clearly inadequate, especially in their later years, notably those of the then Great Southern Energy (a tapering-off of GSE’s projected expenditures in the later years of the 1998 projections appears, retrospectively, to be hard to explain) and those of Australian Inland (it projected a fall in growth capex to low levels but growth, excluding the impact of its CRNP customer, continued).

We asked the DNSPs to give reasons for the overruns under the following headings and their responses are presented and discussed in later sections of this report:

(a) Changes in projected or actual load or in load patterns during the period;
(b) Changes in installed unit costs from those assumed in the 1998 projections;
(c) The need for compliance with new statutory obligations, if any;
(d) The advancement or deferral of expenditures during the period other than for the preceding reasons;
(e) Adoption of new policies, planning criteria or designs following amalgamation with other DNSPs;
(f) Planning or budgeting errors (e.g. cost under-estimation, failure to plan to avoid construction bottlenecks, etc);
(g) The extent to which Y2K or full retail contestability costs added to expenditure;
(h) The extent to which changes in policy for overhead cost allocation increased the cost of capital works;
(i) The extent to which non-network solutions and demand-side management measures reduced capex;
(j) Other factors, for example: the net cost after insurance recoveries of remedying damage.

The DNSPs responded and the following points were noted:

- Non-system capex overruns were material as already noted (CE cited this as a particular reason for its overrun);
- Expenditure on IT system improvements was material in some cases and most DNSPs report a need for further expenditure in this area;

- Higher-than-expected growth in demand was cited as a reason for capex in Sydney and some other areas but, overall, overruns in growth capex were not amongst the highest in absolute terms or as percentages;
- Air conditioning load growth and a shift in peak demand from winter to summer in some locations were also cited as factors and there is evidence that this change took place. It affected plant ratings and helped lead to a requirement for capex in certain areas;
- Increases in installed costs were not cited as a significant factor in the overruns;
- A perceived need for increased expenditure on refurbishment was cited in several cases but asset ages did not suggest urgency in all cases and the expenditures reported in Table 6 do not indicate overruns in this area as a major contributor to the over-spend;
- Additional statutory obligations were cited as a reason for cost overruns and in some cases their impact was quantified. Where quantified, however, the impacts were not as significant as those of the other causes mentioned. It was not clear in all instances that the obligations cited were new ones arising during the period;
- Y2K and costs associated with FRC were identified and had not been projected but they were not the main cause of the overruns;
- Demand management measures were cited as a cost but the figures were not material on their own;
- The cumulative effect of these items was material.

We also reviewed selected project and programme expenditures for prudence – generally the most material ones in each case – and found them acceptable in terms of magnitude, noting the point made in Section 2.12 above regarding the optimality of their timing.

We recognised that the winter-to-summer load shift in certain areas drove capex in some locations but considered that it was not a change that could be argued again as a reason for further augmentation of the same assets.

We took the view that the responsibility for ensuring that adequate allowances were made in their 1998 submissions for their non-system capex and other needs lay with the DNSPs and that overruns should have reason.

After receiving explanations of the additional expenditures we found no reason to judge the individual project and programme expenditures incurred during the period imprudent.

For completeness we also compared the actual expenditures with the figures we (Worley) approved in 1998 and 1999 and the results are summarised in Table 6A below. The only material change between the DNSPs' projections and ours arose in EA's case as we proposed a 29% increase in its expenditure.

Table 6A: Projected v. Actual Capex FY 1999-2003
(Comparison with Worley 1998 Figures)

	AI	CE	EA	IE
DNSP's projections (from Table 6) ($m)	15	784	687	437
Worley 1998 projections for FY 1999-2003 ($m) a/	16	793 b/	885	412
Actual expenditures (from Table 6) ($m)	21	1,002	1,383	778
Actual as pct of Worley 1998 projections before adjustment for additional expenditures or costs considered prudent	131%	126%	156%	188%

Figures have been rounded.
a/ Source: tables in Worley's Final Report of 1998.
b/ Includes increases agreed in 1999.

4.2 Capex Projections for FY 2004-2014

The DNSPs' projections of capex for the period FY 2004-2014 are shown in the Table 7 below based on the primary purpose of the expenditure. Expenditures in each category as a percentage of the total are also shown, as are the total annual expenditures as a percentage of indicative network replacement cost and the implied weighted average age of the assets as a percentage of standard life.[13] All figures are in real (FY 2003) dollars (CE's figures were presented to us in nominal dollars and we converted them using the escalation rates indicated in its template).

Significant changes were made to the figures in the table when errors and omissions in the DNSPs' templates were corrected following the presentation of our interim Draft Report. The main changes arose through the addition to IE's and EA's projections of estimates for possibly excluded services and through the separation of non-network expenditures from other renewal (end-of-life) expenditures. The assistance of the DNSPs in correcting the figures and resolving inconsistencies is acknowledged and was appreciated.

EA's figures exclude its transmission expenditures.

[13] These latter two figures are based on simplifications but are adequate for the points made. The network replacement costs referred to are the asset revaluations just completed.

Table 7: Capex Projections, FY 2004-2014

	AI	CE	EA	IE
Projected renewal capex – end of life ($m)	0	929	1,264	939
Projected renewal capex – environmental etc ($m)	5	0	450	39
Projected non-network capex ($m)	8	660	390	194
Total projected renewal / replacement capex ($m)	13	1,589	2,104	1,172
Projected growth capex ($m)	7	712	1,893	1,178
Projected reliability improvement capex ($m)	9	0	224	177
Sub-total	30	2,300	4,221	2,528
Projected capex for possibly excluded services ($m)	15	621	515	557
Other projected capex (Y2K and FRC) ($m)	0	0	16	0
Total annual average expenditure ($m)	4	266	432	280
Expenditure in each category as pct of total				
Renewal	0	32	27	30
Environmental, safety, statutory, etc	12	0	9	1
Non-network expenditure	18	23	8	6
Total renewal / replacement	30	55	44	37
Growth	16	24	40	38
Reliability improvement	21	0	5	6
Sub-total	67	79	89	82
Capital contribution work	33	13	7	13
Other poss. excluded services (metering, public lighting)	0	8	4	5
Full retail contestability costs	0	0	<1	0
Total	100	100	100	100
Network investment at replacement cost ($m) (ex Table 2)	260	7,909	c.10,927	c.6,208
Network investment at depreciated replacement cost ($m)	168	3,733	c.4,698	c.3,382
Implied weighted average age of assets as pct of std life	35%	53%	57%	46%
Annual renewal /replacement expenditure as pct of network RC	0.5%	1.8%	1.8%	1.7%
Average growth capex as pct of network RC	0.25%	0.8%	1.6%	1.7%
Total annual expenditure as pct of network RC	1.5%	3.4%	4.0%	4.5%

Figures have been rounded.

The table shows that:

- AI has the youngest assets, the lowest projected renewal expenditure as a percentage of network replacement cost, the lowest projected total annual expenditure as a percentage of replacement cost, and the lowest renewal expenditure as a percentage of total expenditure over the period (nil in that case);

- This reflects a significant expenditure on renewals over the last decade;
- EA has the oldest assets, although not greatly older than CE's;
- EA, CE and IE have similar renewal expenditures as a percentage of network replacement cost (1.7-1.8%);
- IE's total expenditure as a percentage of network replacement cost is higher at 4.5% than EA's or CE's at 4.0% and 3.4% respectively;
- There are differences in the categorisation of expenditures by prime purpose with CE, for example, reporting none for environmental, safety or statutory reasons;
- Although not shown in the table, some of the reliability improvement capex is for non-network expenditure such as SCADA.

We noted IE's reference to extreme high temperatures and consequential heavy plant loadings – the loading of plant like transformers increases with ambient temperature – but noted also that they did not appear to have been relied on by IE as a key driver of their capex programme and that their load forecast was based on long-term average weather data.

We noted that capex with reliability improvement as the stated prime purpose received little focus although all DNSPs made the point, correctly, that renewal and growth capex generally had the propensity to bring about reliability improvements.

Examination of selected projects and programmes confirmed, as already noted in Section 2.15, that those planned for implementation later in the period were generally not yet planned or designed in full detail and that decisions will be taken later on whether, when, and in what form they will be implemented. Forward capex programmes are tentative to this extent. This is generally the case in network planning, especially at the distribution level. For this reason, and because of the limited scope of our review, we could not establish the precise links between the established need for certain projects and programmes and their proposed timing. However, such investigations as were within the scope of our review suggested that the capex projects and programmes put forward by the DNSPs were reasonable including their timing.

We formed the view that the projected expenditures might thus be representative of capex requirements overall and could be accepted on this ground based on consideration on their overall magnitude as well as their general their composition. IPART, anyway, will reflect the aggregate capex programme of each DNSP in its modelling without endorsing individual works. If the programme were to be accepted as reasonable on the basis amongst other things of its overall magnitude such acceptance should be accompanied by an expectation that DNSPs will be able to show, at the end of the period, that the magnitudes of their expenditures were in line with the projections. This outcome, however, was not achieved in respect of the period FY 1999-2003.

Projected capex for possibly excluded services related mainly to customer-funded and developer-funded work and to a lesser extent to metering and public lighting. We have already noted in Section 2.20 that expenditures on customer and developer-funded works are made in response to demand and are not necessarily under the DNSP's direct control.

We noted that CE's budget for possibly excluded services included an allowance for the installation of time-of-use meters for new small customer connections.

Future expenditures on FRC were reported only by EA and at a reduced level. We have no basis on which to assess the efficiency of the investments, which are minor in comparison with total projected capex. IPART may wish to consider whether to recognise this expenditure in its determination. There is obviously no future expenditure projected for Y2K.

4.3 Opinion

Overall, capex in the range 4% to 4.5% of network replacement cost as proposed by EA and IE respectively (see Table 7) appeared high to us in the prevailing low-growth environment. We therefore reviewed the projections of these two DNSPs again in consultation with them before reaching a conclusion.

We concluded, and recommend to IPART for its consideration, that the overall capex programmes of EA and IE for FY the period 2004-2009 be reduced in IPART's modelling for the purpose of its determination to a level that we express as a percentage of current network replacement cost. The main reasons for the proposed reductions were doubts over the methodology used to determine the magnitude and timing of replacement capex (see Sections 2.10, 2.18, 6.3 and 7.3) and a general concern over the magnitude of the capex programmes in aggregate (see Sections 2.16 and 4.2). The reductions proposed are as follows: (a) EA's growth capex projections would be accepted as put forward to us for review (they are equivalent to 1.6% of current network replacement cost as indicated in Table 7) but its projections of capex for other purposes would be reduced from the 2.4% indicated in Table 7 (balance of 4% less 1.6%) to 2.0% expressed as a percentage of current network replacement cost, giving a total percentage of 3.6%; and (b) IE's growth capex projections would be accepted as put forward to us for review (they are equivalent to 1.7% of current network replacement cost as indicated in Table 7) but its projections of capex for other purposes would be reduced from the 2.8% indicated in Table 7 (balance of 4.5% less 1.7%) to 2.4% expressed as a percentage of current network replacement cost, giving a total percentage of 4.1%. The reduction proposed is equivalent to 10% and 9% for EA and IE respectively.

We did not consider adjustment of the capex projections of CE or AI necessary.

All capex projections for FY 2004-2014 have been presented in FY 2003 dollars but, for the reasons given in Section 4.1, it should not in our view be assumed that they will be inflated automatically by IPART for notional increases in construction and installation costs for the purpose of future assessment unless justification is provided.

We understand that should IPART decide to accept these recommendations the DNSPs would not be obliged to spend this amount nor be constrained from spending more; and that responsibility for determining an appropriate prioritisation of expenditure remains with the DNSP concerned as discussed in Section 2.19.

5.0 Operating and Maintenance Expenditure

5.1 Opex in FY 1999-2003

Next, we undertook a review of opex in the period FY 1999-2003 to help establish a view on the reasonableness of past opex and thus a view on the starting level for reasonable future opex. Amounts projected and expended during the period are summarised in Table 8 below. All figures are in nominal dollars (AI presented its 1998 projections in real terms and we inflated them to nominal dollars using the escalation rates cited in CE's template – the only ones available to us from the DNSPs).

To help determine the prudence of these expenditures we asked the DNSPs to break down their projected and actual opex under the headings shown in the table. Initially, the data received contained errors and inconsistencies as reported in our interim Draft Report but adjustments were made by the DNSPs to remove these completely as far as we are able to tell.

In some instances expenditures had obviously had to be re-categorised to fit historical or projected data into the reporting categories we requested. For example all DNSPs except EA reported their projections only under the heading 'other opex'. The assistance of the DNSPs in correcting errors and resolving inconsistencies put the analysis on a sound footing. We acknowledge their assistance during this period.[14]

Based on the corrected figures reported in the table actual opex for all DNSPs was within 2% to 3% of their 1998 projections.

AI has the highest opex as a percentage of network replacement cost (2.8%) and EA the lowest (1.9%). CE and IE reported expenditures at an intermediate level (2.3-2.5%).

The biggest expenditure category in all but CE's case was 'other operating costs'. IE cited adjustments to its superannuation provision, wage increases and insurance cost increases as the three biggest drivers in this category (accounting for around three quarters of it) as well as the cost of customer service obligations which it said had been 'incorrectly booked to regulated networks operating units'. EA cited insurance cost increases, occupational health and safety cost increases and other factors. AI and CE indicated similar causes.

[14] The principal reasons for changes from the figures in our interim Draft Report were the removal of line costs from AI's figures (the other DNSPs had not included them), removal of transmission-related expenditures from EA's data, inclusion of missing years' data in CE's and EA's actual expenditures, reconstitution by CE of projections for its pre-merger entities, and the elimination of some duplicated entries in IE's case.

Table 8: Opex, FY 1999-2003

	AI	CE	EA	IE a/
Projected – network operation ($m)	0	0	153	0
Actual ($m)	1	137	157	108
Projected – pole replacement ($m)	0	0	20	0
Actual ($m)	4	35	22	5
Projected – reactive maintenance ($m)	0	0	371	0
Actual ($m)	5	345	183	66
Projected – vegetation control ($m)	0	0	0	0
Actual ($m)	1	97	74	53
Projected – other preventive maintenance ($m)	0	0	0	0
Actual ($m)	8	45	78	96
Projected – other operating costs ($m)	37	880	458	774
Actual ($m)	17	249	507	436
Projected – Total ($m)	37	880	1,002	774
Actual Total ($m)	36	907	1,021	765
Actual expenditures as pct of total				
Network operation	3	15	15	14
Pole replacement	12	4	2	1
Reactive maintenance	14	38	18	9
Vegetation control	4	11	7	7
Other preventive maintenance	21	5	8	13
Other operating costs	47	27	50	57
Total	100	100	100	100
Actual expenditure 1999-2003 as pct of projected	98%	103%	102%	99%
Actual expenditure in 2003 as pct of actual in 1999	147%	123%	103%	141%
Network investment at replacement cost ($m) (ex Table 2)	260	7,909	c.10,927	c.6,208
Average actual expenditure p.a. FY 1999-2003 ($m)	7	181	204	153
Average actual p.a. as pct of network replacement cost	2.8%	2.3%	1.9%	2.5%

Figures have been rounded.

We asked the DNSPs to identify the reasons for departures from their projections under the following headings:

(a) Opex arising each year during the period as a direct result of the amalgamation of your DNSP with others;

(b) Opex resulting from the need to comply with new statutory obligations that came into effect during the period and describe the nature of the obligations;

(c) Opex resulting from non-network solutions and the extent to which it exceeded your projections;

(d) The balance of the difference between projected and actual opex;
(e) Opex incurred in relation to Y2K and full retail contestability during the period.

The main points made in response by the DNSPs related to:

- New requirements for occupational health and safety including stipulations for work in confined spaces such as underground substations – all DNSPs were affected by OH&S issues generally but the confined spaces issue affected EA's costs in particular;
- Charges arising near the end of the period in relation to superannuation schemes and arising from higher insurance costs;
- Merger costs in FY 1999 identified by some DNSPs (IE quantified them);
- Other costs identified by the DNSPs – see in particular Sections 6.4 and 7.4 of the report.

With the exception of EA all DNSPs showed significantly higher opex in FY 2003 than in FY 1999. The percentage increase ranged from 123% to 147% (EA 103%). We investigated the reasons for these increases and were satisfied that there were explanations for the movement. We noted also in this context that, in spite of the increases from FY 1999 to FY 2003, actual opex for regulated services was closely matched to the DNSPs' projections and that no overall overrun had arisen during the period.

Opex relating to possibly excluded services and other expenditures was requested and is summarised in Table 9 below. All figures are in nominal dollars. Y2K and FRC-related expenditures were minor in comparison with total opex but were treated by us in accordance with Section 2.21.

Table 9: Possibly Excluded Services and Other Opex, FY 1999-2003

	AI	CE	EA	IE
Projected – opex assoc. with customer-funded cons. ($m)	0	0	0	0
Actual ($m)	<1	0	0	0
Projected – opex assoc with ancillary services ($m)	0	0	0	0
Actual ($m)	<1	13	18	2
Projected – meter maintenance ($m)	0	0	0	0
Actual ($m)	<1	0	9	0
Projected – metering services ($m)	0	0	42	0
Actual ($m)	3	32	50	28
Projected – public lighting ($m)	0	0	45	0
Actual ($m)	1	20	44	22
Projected – total ($m)	0	0	87	46 a/
Actual – total ($m)	4	65	121	52
Actual expenditure in 2003 as pct of actual in 1999	131%	115%	315%	165%
Other expenditures				
Projected – Y2K ($m)	0	0	23	0
Actual ($m)	0	0	10	5
Projected – FRC ($m)	0	0	50	0
Actual ($m)	<1	7	41	6

Figures have been rounded.
a/ IE deducted this amount from its figure in Table 8 for 'other operating costs'.

Total Opex

Since the definition of 'possibly excluded services' used in the report post-dated the 1998 capex review and 1999 determination we prepared Table 10 below showing the total opex for regulated services, possibly excluded services and other opex.

Table 10 shows the complete picture as far as opex is concerned and indicates average actual expenditures as a percentage of network replacement cost of between 2.2% and 3.2%. Points noted were:

- AI had the highest opex as a percentage and EA the lowest, probably reflecting their relative economies of scale and other characteristics;
- It was not clear to us why IE's opex exceeded CE's as a percentage (it did not do so by much) as it would appear logical that it lie between CE's and EA's;[15]

[15] IE pointed out that there are a number of possible explanations for this.

- Overall, our initial view was that opex as a percentage of network replacement cost appeared high to us based on our experience, noting also that Y2K and non-approved (non-incremental) FRC costs, although small, needed to be added.

Table 10: Total Opex, FY 1999-2003

	AI	CE	EA	IE
Projected – regulated services ($m)	37	880	1,002	774
Actual ($m)	36	907	1,021	765
Projected – possibly excluded services as currently defined ($m)	0	0	87	46
Actual ($m)	4	65	121	52
Projected – Other opex (Y2K and FRC costs) ($m)	0	0	73	0
Actual ($m)	<1	7	51	11
Projected – total ($m)	37	880	1,162	820
Actual – total ($m)	41	980	1,194	828
Actual in 2003 as pct of actual in 1999	146%	125%	118%	141%
Average actual expenditure p.a. FY 1999-2003 ($m)	8.2	196	239	166
Network investment at replacement cost ($m) (ex Table 2)	260	7,909	c.10,927	c.6,208
Average actual p.a. as pct of network replacement cost	3.2%	2.5%	2.2%	2.7%

Figures have been rounded.

For these reasons, noting also the high proportion of opex for regulated services accounted for by the ‘other operating cost’ category, we again examined the opex expenditure data and consulted with the DNSPs. Details of their responses are incorporated in the later sections of the report.

5.2 Cost-Based Performance Measures

To further assist us in assessing the efficiency of the DNSPs’ operations but not as an inviolate guide, we asked DNSPs to complete a table of cost-based performance measures to demonstrate the efficiency of their operations and cost structures. Their responses are summarised in Table 11 below for FY 2003. The terms used (direct and indirect costs) were defined as follows:

- *Direct costs:* Direct costs are those directly related to operating and maintaining the network business of a DNSP: (a) including all costs that (i) are directly related to managing the system or (ii) are for the purpose of maintaining the service potential of system fixed assets; (b) excluding indirect costs, capital expenditure, depreciation, interest, amortisation of goodwill and intangibles, subvention payments, expenditure in relation to leased assets, transmission charges, avoided transmission charges, corporate tax, GST and other taxes except those incurred in the procurement and delivery of equipment;

- *Indirect costs:* Indirect costs are those not directly related to operating and maintaining the network business of a DNSP: (a) including all costs that (i) are not directly related to managing the system or (ii) are for a purpose other than maintaining the service potential of system fixed assets; (b) excluding direct costs, capital expenditure, depreciation, interest, amortisation of goodwill and intangibles, subvention payments, expenditure in relation to leased assets, transmission charges, avoided transmission charges, corporate taxes, GST and other taxes except those incurred in the procurement and delivery of equipment.

Table 11: Cost-Based Performance Measures (FY 2003)

	AI	CE	EA	IE
Total direct cost of opex ($m)	4	111	184	78
Total indirect cost of opex ($m)	5	85	75	71
Total direct cost per km of system length ($)	440	608	3,897	2,316
Total indirect cost per customer connected ($/cust)	277	117	51	83
Total direct+indirect cost per kWh sold (cents)	2.2	1.9	0.9	0.9
Total direct+indirect cost per system length ($/km)	1,000	1,077	5,486	4,286
Total direct+indirect cost per customer ($/cust)	500	270	175	181
Total direct cost – materials ($m)	d.n.s.	25	14	9
Total direct cost – labour ($m)	d.n.s.	66	107	71
Total direct cost – plant ($m)	d.n.s.	19	63	1
Total indirect cost – admin & other bus unit overheads	d.n.s.	73	55	47
Total indirect cost – corporate cost allocation ($m)	d.n.s.	12	20	23

For comparative purposes Table 12 below presents the same information for New Zealand's DNSPs, based on their most recent (2002) information disclosures under the Electricity (Information Disclosure) Regulations. The New Zealand DNSPs are of interest because they have similarities in design and operational practice to the NSW DNSPs, have undergone significant rationalisation and commercialisation since the mid-1980s; have exhibited material efficiency improvements over that time, and have reliable performance data of the type required available.

Comparison of Table 12 with the figures in bold in Table 11 shows that:

- EA's direct costs per unit of system length exceed the New Zealand maximum by 70% and IE's exceed it marginally but the rest of the NSW DNSPs are within the New Zealand range (AI's are significantly below);
- Not surprisingly, AI's indirect costs per customer connected exceed the New Zealand maximum significantly but the rest of the NSW DNSPs are within the New Zealand range;

- Total direct plus indirect costs per kWh sold are comparable but the minimum in NSW is 50% above the minimum in New Zealand;
- Total direct plus indirect costs per system length are comparable and the maximum in NSW is 10% less than the maximum in New Zealand;
- Total direct plus indirect costs per customer connected are comparable.[16]

Table 12: Cost-Based Performance Measures for New Zealand DNSPs in 2002

	Mean	Median	Minimum	Maximum
Industry profile				
System length (km)	5,000	3,700	240	30,000
Customer connections (No)	61,300	25,700	4,100	505,000
Cost-based performance measures				
Total direct cost per km of system length ($)	1,167	1,036	574	2,290
Total indirect cost per customer connected ($/cust)	63	62	23	144
Total direct+indirect cost per kWh sold (cents)	1.2	1.1	0.6	2.3
Total direct+indirect cost per system length ($/km)	1,925	1,550	783	6,083
Total direct+indirect cost per customer ($/cust)	187	171	116	447

Source: *Electricity line business and gas pipeline business 2002 information disclosure compendium*, Pricewaterhouse Coopers, January 2003.

Care is needed in the interpretation of the figures, noting the differences between the DNSPs. However, the comparison does tend to support our own assessment based on experience that, although the NSW DNSPs have no doubt improved their operations over time, there are further efficiency gains to be achieved. The magnitude of possible gains cannot be deduced or implied from the comparison presented above but can only be conjectured without undertaking a detailed study beyond the scope of this review.[17]

5.3 Opex Projections for FY 2004-2009

The DNSPs' opex projections for the period FY 2004-2009 were requested and are shown in Table 13 below. All figures are in real terms (CE presented their information in nominal terms and we converted the data at the rates they provided in their template). Points noted were:

- AI's projections showed an increase from FY 2003 to FY 2004 but this was off-set by a decrease from FY 2004 to FY 2009, the overall increase from FY 2003 to FY 2009 being around 4%;

[16] The New Zealand data is presented in NZ dollars and the NSW data in Australian dollars. Adjustment for currency exchange rates was not considered appropriate.
[17] We took into account independent benchmarking opinions carried out for certain DNSPs and provided to us. These included an opinion from SKM that EA's capex and opex allowed for in the 1999 determination "were significantly below the industry average" and an opinion from UMS that CE was under-spending on capex.

- CE's projections showed no movement from FY 2003 to FY 2004 but a 9% increase from FY 2004 to FY 2009;
- EA's projections showed an increase of 7% from FY 2003 to FY 2004 and a further increase of 8% from FY 2004 to FY 2009;
- IE's projections showed an increase of 7% from FY 2003 to FY 2004 but, as with AI, this is off-set by a decrease from FY 2004 to FY 2009, the overall increase from FY 2003 to FY 2009 being just under 4%;
- In summary the increases projected by EA and CE were higher than for the other two DNSPs and were occasioned by increases from FY 2004 onwards that bore a reasonable correlation with projected energy sales growth.

Table 13: Opex Projections for FY 2004-2009

	AI	CE	EA	IE
Network operation ($m)	3	162	249	153
Pole replacement ($m)	5	0	43	0
Reactive maintenance ($m)	1	430	383	101
Vegetation control ($m)	1	114	119	105
Other preventive maintenance ($m)	15	53	154	229
Other operating costs ($m)	29	485	538	524
Total ($m)	100	1,244	1,486	1,111
Expenditures as pct of total				
Network operation	5	13	17	14
Pole replacement	9	0	3	0
Reactive maintenance	2	35	26	9
Vegetation control	3	9	8	9
Other preventive maintenance	27	4	10	21
Other operating costs	53	39	36	47
Total	100	100	100	100
Projected expenditure in 2004 as pct of 2003	112%	100%	107%	106%
Projected expenditure in 2009 as pct of 2004	93%	109%	108%	96%

We asked all DNSPs for further information about the expenses in the 'other operating costs' category. They identified the main items as follows:

- AI: overheads of various types;
- CE: meter reading and data services, customer services, advertising and marketing, public lighting and corporate/administration allocation;
- EA: provided us with a detailed opex expenditure review and projection prepared for it by SKM for FY 2004-2009;

- IE: provided details in support of its costs including, in particular, its costs for FY 2004 since it said they included several extraordinary items. Details are given in later sections of the report.

One of the main thrusts of the report prepared for EA was that EA's opex was below a benchmark line of expenditures of Australian DNSPs. It appeared that, in determining an appropriate line, the advisers removed EA's 1998 determination from the data, re-fixed the benchmark line and then proposed to EA that it should be on it. EA noted that it had arrived at a similar level of expenditure independently. The resulting increases in opex, if agreed to, would have the effect of repositioning EA in relation to its peers in the industry (as expressed in the adviser's analysis). We felt that removed existing and desirable economies. The report presented other arguments for its case and we considered them but decided to retain our own view of the situation.

5.4 Possibly Excluded Services and Other Expenditures

Opex projections relating to possibly excluded services and other expenditures over the period FY 2004-2009 were requested from the DNSPs and are summarised in Table 14 below. All figures are in real terms.

Table 14: Projections for Possibly Excluded Services and Other Opex Expenditures

	AI	CE	EA	IE
Associated with customer-funded connections ($m)	<1	0	0	0
Associated with customer-specific ancillary services ($m)	1	18	28	17
Meter maintenance ($m)	1	0	12	0
Metering services ($m)	1	46	76	50
Public lighting ($m)	1	27	76	35
Total ($m)	5	91	193	102
Projected expenditure in 2004 as pct of 2003	90%	100%	104%	107%
Projected expenditure in 2009 as pct of 2004	85%	107%	124%	108%
Other expenditures				
FRC related expenditures ($m)	0	1	84	26

Points noted were:

- CE and IE projected nil expenditure for meter maintenance;
- AI projected a declining expenditure;
- CE projected an increase over the period of 7%;
- EA projected an increase of 24% over the period on top of an increase of 4% in FY 2004;

- IE projected an increase of 8% over the period on top of an increase of 7% in FY 2004;
- Only IE and EA projected material amounts for FRC.

Overall, the increases over the period in the projected cost of possibly excluded services appeared to be justifiable except that EA's increase was high. We therefore examined it further and determined that it was driven principally by a projected increase in the cost of public lighting. We noted also that EA's projected expenditure for these services is equivalent to only about 10% of its projected opex for regulated services.

We examined the reasons for IE's projected increase and found that it was spread across all categories.

5.5 Opinion

In reaching our conclusions regarding opex we noted the following principles:

- The principal purpose in reviewing opex during the period FY 1999-2003 was to help determine a reasonable starting level for future opex;
- As with capex, acceptance of the overall level of future opex should have regard to the general factors set out in Section 2, particularly Section 2.16;
- Opex should reflect economies of scale;
- Opex should also reflect other pertinent considerations including asset ages noting that aged assets involve more cost than new ones;
- Opex movements over time will reflect changes in the cost of its constituent components – on average 40% labour, 38% overheads, 14% plant and 8% materials according to the data in Table 11;
- The possibility of off-setting savings, as discussed in Section 2.22, should be recognised; and
- The treatment of Y2K- and FRC-related costs should be as set out in Section 2.21.

Our opinion is as follows:

a) We found no reason to conclude that opex during the period FY 1999-2003 was imprudent;
b) We considered the FY 2003 opex figures as agreed with us and presented in the later sections of the report to be a reasonable and balanced starting level in all cases for the determination of future opex in accordance with the recommendations that follow;
c) We saw no reason for opex movements in real terms from FY 2003 onwards to exceed a reasonable allowance for increase in scale of operation, given adequate capital investment;
d) We noted that opex increases were projected to be less than this in the case of some DNSPs;

e) We were not able to quantify possible efficiency gains based on the scope of our work although our work suggested the prospect of some; and

f) We recognised that capex reductions might make it harder for DNSPs to achieve their targets without a corresponding increase in opex.

We recommend for IPART's consideration the following actions in respect of projected opex for the period FY 2004-2009:

i) The implicit re-positioning of EA's opex not be agreed to;

ii) To give effect to (i) above EA's opex be adjusted to reflect an increase of no more than 10% in nominal terms from FY 2003 to FY 2009;[18] [19]

iii) Opex for the other DNSPs be accepted as projected;

iv) Before automatically adjusting the projections in future assessments for notional changes in the cost of materials, labour or plant, the cost of opex should be examined to check that DNSPs are maintaining cost-effective operational structures and practices and that their overheads are reasonable.

As in the case of capex we understand that should IPART decide to accept these recommendations the DNSPs would not be obliged to spend this amount nor be constrained from spending more; and that responsibility for determining an appropriate prioritisation of expenditure remains with the DNSP concerned.

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[18] The FY 2003 expenditure level referred to is that presented by EA in its templates and summarised in Table 16 in Section 6 of this report.

[19] A 10% increase is equivalent to an annual average increase of 1.6% compounded over the six-year period. 1.6% is the forecast rate of growth in energy delivery in EA's most likely growth scenario. This is taken as a reasonable base for opex growth.

6.0 Assessment – Energy Australia

6.1 General

General Information and Documentation

The following general information and documentation was obtained from EA and reviewed:

(a) Recent annual reports;
(b) Organisation chart, employee numbers and contracted services;
(c) Statement of corporate intent;
(d) Asset management policy manual;
(e) Capital works plans;
(f) Selected procurement and construction specifications;
(g) Recent network performance reports;
(h) A sample of the network single-line diagrams and maps.

We were given a summary of assets in service at 30 June 2002 and their age profile. A summary of the latter is reproduced in Table 15.

We obtained and reviewed general statistics and system performance data as summarised in Section 3 of the report. We received and reviewed sub-transmission network utilisation data in relation to the planned major projects in Newcastle and Sydney. We received and briefly reviewed information on zone substation utilisation for the years 2002 and 2009.

Demand Forecast

We received information from EA on its forecasting methodology and three load growth scenarios. We were advised that EA routinely produces two forecasts: global forecasts of total energy consumption and peak demand; and spatial peak demand forecasts at the sub-transmission substation level as well as for each of 170 zone substations. The global energy consumption forecasts form the basis for revenue budgeting and the spatial peak demand forecasts form a key input to network capex planning. The global peak demand forecasts, which are based on the same assumptions as the energy forecasts, are used only as an independent check on the spatial forecasts. Both sets of forecasts rely on analysis of historical growth trends and of the drivers behind those trends. The spatial demand information is adjusted for switching and load transfers across zone boundaries to ensure consistency as far as possible in the historical demand series. In developing the spatial peak demand forecasts, the impacts of abnormal weather conditions are identified and isolated from observed historical trends.

The global forecasts rely on an end-use model for residential load, which represents around 34% of sales. The peak demand forecasts rely heavily on the results of an ongoing load research programme undertaken by EA. One of the important results from the programme has been an enhanced understanding of customer behaviour, particularly customers with air conditioning.

We noted that EA's forecasts are used by TransGrid for its planning purposes and by NEMMCO for its statement of opportunity planning and this lent a further level of comfort to the representations made to us by EA.

We considered EA's medium-growth forecast to be the appropriate choice for the purpose of our review.

Demand-Side Management

We were advised that approximately 1,400 MW of load was controlled by ripple control systems and time clocks. EA also reported that it had interruptible load tariffs in use.

EA reported that it had introduced processes and established a new unit specifically responsible for exploring demand management alternatives. EA briefed us on its operations. Current processes also include the publishing of option papers which enable the submission of demand management ideas and costs by interested parties in order to address particular system constraints. In addition EA carries out demand management opportunity assessments for major customers in constrained areas.

A thrust of its current programme is to "learn by doing", the aim being to develop a better knowledge and understanding of the costs and characteristics of DM projects. EA is working with SEDA and others to get some sample projects under way to test their benefits before expanding the work further.

We concluded, however, that demand management prospects in EA's area are not likely to have a material impact on their capex requirements within the period FY 2004-2009 but have the propensity to make a meaningful impact in the future.

Distributed Generation and Other Non-Network Solutions

EA advised us that it does not keep records of all generators connected to its network. However it is aware of larger installations and has indicative data on some smaller installations. EA staff gave us details.

EA gave us details of distributed generation installations for which it has received a request for connection and where the project is under construction. The installations are small compared with the EA's demand – between 20 kW and 5.6 MW – and EA staff advised us that the projects are not expected to have an impact on projected capex.

EA advised us that it is not currently considering developing distributed generation projects itself. However, as part of its investigations of demand management options, it may identify projects that it would support in order to defer expansion of the network. There are no projects currently subject to such an offer.

EA is also pursuing some distributed generation projects as part of the 'learn by doing' programme already mentioned. There is one project of this type currently being implemented at North Ryde. The background to the project is that there was a prospect of overcoming network constraints in the area in the 1990s by use of the generating plant. However, during the so-called 'tech boom', a prospective load of around 40 MW led to the reinforcement of Macquarie Park zone substation instead. The 40 MW load did not eventuate but the additional capacity at the zone substation did serve to reduce excessive loads at adjacent zone substations. EA have now proceeded with the generation arrangement anyway. There is no material impact on network expenditure.

EA expect other projects to arise but do not have details.

Consideration of the use of distributed generation – not actually the right term to describe it because of its size – in conjunction with the joint EA-TransGrid Sydney reinforcement project is discussed in Section 6.2 in the context of prudence of past capex.

We concluded that embedded generation prospects in EA's area within the period FY 2004-2009 are not material in terms of this review.

Independent Forecast

We were provided with data to prepare our own forecast of future demand but, on review of EA's own forecast, noting its comprehensiveness and its use by other outside parties, we concluded that (a) we could not improve on the accuracy of EA's own forecast with the data available to us; and (b) EA's forecast was in our opinion reasonable for the purpose of this review.

6.2 Actual v. Projected Capex for FY 1999-2003

Definition of Capex

We asked EA to confirm its definition of capex with reference to the NSW Treasury's *Guidelines for capitalisation of expenditure in the NSW public sector, June 2000* and were advised that its practice is to classify expenditure as capital if the definition and recognition criteria for an asset in SAC 4 *Definition and recognition of the elements of financial statements* is met.

Actual v. Projected Capex

EA was asked to enter its actual capex in the years FY1999-2003 under certain prescribed headings in the template together with its capex projections made at the time of the 1998 capex review. EA reported that assumptions had been made to align its historical expenditure with the requested reporting categories and that some inaccuracies may have resulted. We did not consider them likely to be material.

EA was asked to explain the reasons for changes in expenditure under the headings listed below (its responses are given in parenthesis): [20]

(a) Changes in projected or actual load or in load patterns during the period (EA replied: "For the first time EA has become a summer peaking network. At the last determination the assumption of summer load growth over the five-year period was 3%, 3%, 2%, 2%, and 2% i.e. an average of 2.4%. In fact summer growth averaged 4.2% over the period. Given that equipment capacity is much lower in summer the impact on capex is obvious. This has been compounded by an un-allowed-for change in customer lifestyle decisions re energy use. For example higher than anticipated penetration of air-conditioning has contributed not only to the volatility of peak loads on hot days but has also extended the load cycle peaks for many residential and commercial zone substations. This reduces the assigned capacity of equipment. For example Pennant Hills zone [substation] has been de-rated by about 5% which is more than the anticipated annual growth rate. EA's submission also contains information on this subject. The number [of] summer-peaking zone substations increased from 25% of all substations representing 28% of load in 1995 to 37% and 42% [respectively] in 1998. This trend is continuing and the number of summer peaking zones is expected to be 56% in 2003 representing 60% of zone substation loads');

(b) Changes in installed unit costs from those assumed in its 1998 projections (EA replied: "Sinclair Knight Merz have undertaken a capex reconciliation between actual expenditures and Worley/IPART schedules. EA have identified an amount of $59 million for the total determination period reflecting discrepancies between actual/projected project costs and [the estimates EA provided at the time]');

(c) The need for compliance with new statutory obligations, if any, introduced during the period (EA replied: "EA has assets which, in the majority of cases, were installed in housings, buildings and locations over 40 years ago. There are numerous safety, compliance and regulatory issues today which did not exist when this equipment was commissioned. By today's legislative and regulatory standards

[20] Quotations in this and the following sections of the report may have been abridged.

we would not be allowed to install similar arrangements but due to the number and variety of construction types, we have to maintain and work with these obsolete assets and facilities. The types of restrictions and regulations that are causing high operations costs and access problems are: the large number of underground substations in the Sydney CBD which require fall [arrester] facilities and are confined spaces under the work cover definition; the majority of pits in the city and suburbs are classified as confined spaces; basement jointing chambers in most zone- and sub-transmission substations are confined spaces; approximately 2,000 substations which have restricted access personnel entrances, and restricted or no emergency escape exits; entry methods to access substations (especially zone- and sub-transmission) must be controlled and monitored to ensure safe practices are always observed; house-keeping in many zone substations is causing concern to EA's insurers. Special modifications must be introduced to mitigate consequences of risk and fire; extra-sensitive fire detection schemes must be installed and interfaced with network control via SCADA; environmental legislation compels EA to use experts to identify weeds in yards before removing as legislation is attempting to save endangered flora and our advice states that specialist scientist must certify; with the community and legal trends, many Capital works and/or Infrastructure, require without exception Environmental Impact Study (EIS are usually 3 times cost of Environmental Impact Assessment); with the community and legal trends, all minor works are now requiring an EIA');

(d) The advancement or deferral of expenditures during the period other than for reasons already listed (EA replied: "The … value of projects brought forward into the determination period has been identified by SKM at $81.9 million. SKM also reconciled major projects not identified in the Worley report. These amounted to a total of $152.1 million but were offset by $26.1 million in projects deferred to the next period and by a reduction of $4.0 million in non-major projects. Extremely high growth in customer connections, initially driven by the Olympics but maintained throughout the period, led to an over-expenditure of $183.8 million on new load (obligation to supply). This was accompanied by an underestimation of $62.7 million for 'customer funded' connection asset costs. There was also an underestimate of $24.8 million in franchise metering costs due to the delay in the 'contestability' date from that assumed by IPART [the SKM *Capital reconciliation report* was provided to us]');

(e) Adoption of new policies, planning criteria or designs following its amalgamation if any with other DNSPs (EA replied that this was not applicable);

(f) Planning or budgeting errors (EA replied: 'see [the response to] (d) and note that under- estimations sometimes occurred because of the outcomes of community consultation which altered line routing or forced the purchase of high cost alternative sites as well as the usual problem of unidentified site problems (e.g. sulphate soils at City Central etc)');

(g) The extent to which Y2K or full retail contestability costs added to expenditure (EA replied: "FRC and Y2K costs consistent with regulatory accounts and IPART's ruling on prudent FRC costs have been included in the template. In IPART's letter of 10 July 2002 IPART allowed reasonable and prudent costs of $99,698,218 of EA's claimed $127,637,282. This left $27,939,064 as "costs not reasonably associated with contestability" and the letter noted that "It may be appropriate for EA to recover some of these costs at the next regulatory period (provided they have not previously been recovered and are considered to be prudent by the Tribunal)" IPART's FRC cost consultant has previously indicated all EA's FRC expenditure was considered prudent with the reduction in the claimed amount based on the consultants view of the expenditures as not being "incremental FRC" costs');

(h) The extent to which changes in its policies for overhead cost allocation increased the cost of capital works (EA said there had been policy changes);

(i) The extent to which non-network solutions and demand-side management measures reduced capex (EA replied: "EA has a long and substantial record of the promotion of controlled load tariffs in order to reduce system capex and deliver energy cost savings to customers; EA has also invested in the installation of major capacitor banks at the zone substation and sub-transmission substation levels of the system to gain improvements in power factor as well as to improve voltage regulation and to reduce capex; the licence compliance – demand management returns that have been made by EA over the past three years indicate a net average capex reduction of approximately $8 million p.a. due to demand management; further to this EA, the NSW Government, the electricity supply industry, energy service companies and other organisations have generally been pro-active in the promotion of energy efficiency and demand management; whilst difficult to quantify in terms of capex reductions by EA the outcome of this promotion activity flows through to energy efficiency and demand management actions by individual customers, mitigation of the growth in system loadings, reduced forecasts and reduced capex');

(j) Other factors, for example: the net cost after insurance recoveries of remedying damage (EA replied: "damage can be split as follows: (1) by third parties: treated as repairs as is generically maintenance and as per IPART is considered recoverable, therefore no capex issue; (2) damage by natural disasters: accounting policy is: "Where an asset is damaged, the cost of repairing the asset to the same standard as was the case prior to the damage occurred, is treated as an operating expense" and this means that the service potential or the income generating capacity of the asset should not exceed the level the asset had prior to the damage. EA noted that it is not the severity of the natural disaster/storm or the fact that the work done to restore supply during such times is temporary (to be made permanent at a later date) or permanent, that determines whether the costs are capitalised; it is the nature of the work done and whether the service potential or useful life of the asset has changed; if the service potential or useful life remains the same, it is operating expenditure; if the service potential or useful life increased, it will be capital expenditure; where the asset is re-built to a significantly higher standard than was the case prior to the damage occurring (i.e. where the service potential of the asset is increased) the cost of the repair work should be treated as Capital expenditure because there is in effect the creation of a new asset but the damaged portion of the asset will need to be removed from the asset register by writing off the accumulated depreciation and the historical cost; on this basis the majority of this work is expensed; analysis of capex between 6/98 and YTD 2003 indicates total capex of $9 million').

We discussed these responses with EA and obtained details of the expenditures made and reasons for the material items.

We noted that EA's capex covered the full range of network and non-network expenses including the replacement of obsolete gear, installation of new equipment to improve voltage conditions on the network and to meet load growth, new customer connections, metering and load control equipment, the modification of mobile plant to comply with current requirements and other items. We discussed the scheduled expenditures with EA's staff and concluded that the expenditures were reasonable for the purpose of this review.

We also obtained from EA and reviewed an independent reconciliation of actual v. projected capex during the current regulatory period prepared by SKM and, separately, an independent assessment of the prudence of major projects also carried out by SKM. The latter report discussed both the magnitude of expenditure and the timing of the projects. We did not consider ourselves bound by their conclusions but we were guided by them noting that they reached the same overall conclusion as ourselves in respect of prudence. We did note, however, that SKM's prudence review "did not specifically re-evaluate the range of augmentation options considered, to determine the lowest NPV scheme was adopted, nor to determine that all options had been considered". To have done so would have been a major undertaking: we also faced this problem in carrying out our own review.

We were asked by IPART to look specifically at the Sydney CBD reinforcement project in terms of whether non-network solutions should have been adopted. The impression given to us by the correspondence we received was that the project might have overrun in either cost or time in a way that might have justified non-network solutions. We were advised that non-network options may have compared favourably with the network solution finally recommended and adopted. To examine this matter we obtained from EA the NERA report of February 2000 on the cost-effectiveness of the options available and noted, as best we could judge, that: the report we received was apparently the most recent in of a number of reports on the subject; under all options the lowest cost options involved network augmentation in the first stage of development; the cogeneration and demand side management options were projected to become relatively more attractive in the second stage of development (relative to the results excluding carbon dioxide emissions) compared to pure network alternatives; and, when subsequent augmentation is considered, it would be important to assess demand side management options in light of any updated information that is available at the time. EA reported to us that its costs on the project were still expected to be substantially in accordance with budget and that the project was running substantially on time. We therefore have no reservations about the project form the standpoint of this review and consider it a desirable addition to the Sydney CBD supply.

Our opinion is that, based on the information made available to us and on our own assessment, notwithstanding the comments made above, we had no reason to judge any material component of EA's actual capex during the period FY 1999-2003 imprudent.

Table 16 summarises EA's capex data.

6.3 Capex Projections for FY 2004-2014

Network Planning Criteria

We obtained from EA information on its documented network planning criteria for sub-transmission systems, high voltage distribution systems and low voltage distribution systems. We also asked for and obtained information on the length of planning period assumed in its long-term network planning process. We asked when the criteria had last been reviewed, whether the security of supply criteria were deterministic, probabilistic or both, and what plant rating criteria were applied. EA provided us with comprehensive information in response. We considered the criteria reasonable.

Optimality of Design and Construction Practices

We asked to what extent cable, conductor and equipment sizes, circuit designs and procurement were optimal. EA replied that if it were planning and developing a green-field network it would naturally adopt a different topology but that it was hampered by historical development that occurs on the basis of expectations and technology available at the time. It noted that the network, especially in Sydney, is complex and highly developed so that most augmentations must, if they are to be cost-effective, conform to existing networks. EA noted that every new augmentation or replacement project is subject to a planning review and, in the case of major projects, to a value management study. EA also noted that its planning optimises the use of existing assets as well as new infrastructure.

EA advised us that it had recently analysed its cable requirements and settled on an optimised mix of circuit designs and that it was actively investigating efficient designs for zone substations especially those associated with the rapidly developing Hunter region.

EA advised us that its procurement specifications were not necessarily optimised across all product groups and that in part this was a result of the issues mentioned above concerning the current network and the limitations this presents when specifying new equipment. It said that the specifications are reviewed by cross-functional teams periodically in line with contract renewals and it provided us with information on new technologies and designs in use or under consideration.

We noted these points but they did not affect our view that the designs assumed were reasonable.

Unit Installation Costs and Standard Lives

We asked EA to indicate whether its unit installed costs and standard lives assumed when preparing capex projections were in accordance with Appendix C of the NSW Treasury's Guidelines (there is no requirement for them to be if the alternative approach used is sound). EA replied that it used its own estimates as the standard rates in the Guidelines were not considered appropriate for CBD sites and certain other asset groups. It noted correctly that the Guideline rates are averages that should not necessarily be used for specific project estimates. It therefore used its own estimating rates determined from recent similar projects based, where possible, on competitive bids. It noted that about 80% of the cost arose from external contractors at market rates and only 20% from internal sources.

We accepted the explanations and the accompanying cost estimates as reasonable for the purpose of this review.

Methodology for Determining Replacement Capex

We asked EA to outline its approach to determining replacement capex and noted that condition- and performance-based assessments were used with age used as a proxy for condition where reliable information was not available. It said it optimises its capital and operating expenditure programmes and replaces or refurbishes those assets that cost more to maintain than to replace. EA has also adopted targets to manage the overall age profile of the network: no more than 10% of the total asset base (in dollar terms) shall exceed the regulatory standard asset life; no more than 40% (in dollar terms) of a single category of assets shall exceed the regulatory standard asset life, unless known asset condition overrides this in specific cases; and where condition-monitoring criteria have been established for a specific class of assets, they shall be assessed and in replacement/refurbishment programmes developed to meet the criteria outlined above. These targets, EA said, "seek to avoid the cyclic pattern of initially under-spending then over-spending in replacement and refurbishment as has been the pattern over the last thirty years". EA say that the magnitude of replacement capex proposed reflects a low level of spending in the last decade.

We noted these targets and considered them a possible approach to resolving the uncertainty surrounding the optimal capex-opex trade-off but we had reservations that they might not necessarily lead to a reasonable outcome overall because of their arbitrary nature.[21]

EA provided us with a list of condition assessment surveys carried out since 1998. They appeared comprehensive but a detailed assessment of asset condition was beyond the scope of our review.

We obtained and reviewed the independent assessment of EA's projected O&M expenditure including a high-level capex assessment carried out by SKM this year. Amongst other things the report explained the modelling process that had been used to determine the optimal trade-off between opex and replacement capex expenditures for each main asset group. We accepted the process as being a sound overall guide but did not consider that sufficient data was available to confirm the appropriateness of the various parameters assumed in applying the model. We noted SKM's advice that "this trend [of ageing assets] highlights the impact that a sustained under-spend in refurbishment over a lengthy period of time has had on the financial drain (both capex and opex) required to maintain and refurbish the [EA] system. Significant increased spending is required in both capex and opex simultaneously, and yet average system age will continue to decline…"[22]

We also noted that SKM had prepared a high-level capex forecast of its own that showed lower expenditure overall, $34 million of the reduction being attributable to a lower replacement capex projection.

We noted also that the SKM report gave information on a number of other matters including the increased opex that EA estimated had arisen from recent reduced capex

[21] See also Sections 2.10 and 2.18.
[22] The authors presumably meant 'increase', not 'decline'.

spending, and the additional opex costs that had arisen through 'external' factors – regulation, bush fire mitigation, vegetation management, pole inspections and FRC.

We also noted SKM's view on EA's overall level of opex and have commented on it already in Section 5 of the report.

We did not consider ourselves bound by SKM's conclusions but we were guided by them, noting that they reached a similar overall conclusion to ourselves in advocating a reduction in the magnitude of replacement capex.

Impact of Statutory Obligations on Capex

We asked EA to estimate the impact on capex of statutory obligations including but not limited to safety, environmental protection and quality of supply. EA listed the following requirements that impinged on its operations: the Building Code of Australia; OH&S 2001 Regulations; various heritage Acts; community resistance to the installation of electrical installations; the need to prepare environmental assessments for new work; the need to review existing assets to assess their environmental status and possible need for replacement e.g. oil cables, open-type distribution lines, fuses, oil-filled transformers and older HV switchgear; the need to comply with Planning NSW requirements on cable laying; road loading and traffic restrictions leading to more expensive methods of construction; changes in marine craft making it necessary to rebuild or replace water crossings; the requirements of the Rail Access Corporation MAD agreement; water filtration requirements prior to discharging seepage water from pits and tunnels into storm-water or sewerage systems. SKM quantified the impact of Regulation 2001 as $8.2 million in the current regulatory period. We noted the impacts arising from these reasons and considered the estimates reasonable for the purpose of this review.

Capex Evaluation and Approval Processes

We reviewed the capex evaluation and approval processes followed from project identification to approval and considered them appropriate for the purpose of this review, noting that they had been reviewed by the PA Consulting Group.

Capex Projections

We received EA's projections of capex for the period FY 2004-2014. We were given a detailed schedule of line items making up the projected expenditures and noted that, as in the case of past capex, the expenditures covered the full range of network and non-network expenses including the replacement of obsolete gear, installation of new equipment to improve voltage conditions on the network and to meet load growth, new customer connections, metering and load control equipment, the modification of mobile plant to comply with current requirements and other items. We noted the significant impact of a shift to summer loading.

We asked for and received supplementary information on certain major items of capex including the Sydney CBD reinforcement project, the St George reinforcement project, the East Maitland/Tarro Corridor project, the Mid-Central Coast project and the Newcastle CBD and Surrounds project. These were reviewed. We noted that: the projects were complex; those proposed for implementation in the immediate future had been fully prepared and documented; those proposed for implementation later in the coming regulatory period were not yet fully assessed; those proposed for implementation after the end of the coming regulatory period but within the time frame reviewed were more tentative; most projects were determined after the study of numerous options; we briefly examined the options within the scope of our available time and, although we could not tell with certainty that the chosen options were the most economic or the proposed timing was the most appropriate or the cost estimates were accurate, and although we noticed some inconsistencies in the documentation, we did conclude that (a) with further study, would probably reach the same or similar conclusions to EA; (b) there did not appear to be any material non-network solutions that would address the system problems that were the focus of the projects; and (c) we noted that some of the projects or expenditures related to them had been analysed in SKM's independent report on the prudence of capex up to FY 2004 and reported favourably.

Additionally, we discussed the programme with EA's planning engineers, receiving explanations in response to our questions particularly in relation to network constraints in the Hunter region, the Central Coast and in Sydney and its immediate environs.

We noted that we had ourselves inspected several of the facilities in question during previous work for IPART and EA and were generally familiar with the situation and the condition of the network.

Notwithstanding the comments made we were satisfied, on the basis of the information made available to us, that the individual projects were justifiable for the purpose of this review.

We were not concerned that a high portion of the investment was attributable to works in the Newcastle and Hunter regions since there appeared to be adequate explanation for the works concerned. We noted in that regard that the Central Coast assets were operating at a high level of utilisation and that the principal supply substations and cables in Newcastle warranted refurbishment, replacement or reinforcement.

We were, however, concerned about the magnitude of the capex programme as a whole. The point has already been made in this report that EA's assets are the oldest (by a small margin – see Table 7) of the DNSPs in NSW and that growth in its service area is high compared with other areas (although not projected to be the highest – see Table 5). Also, it has been noted that both EA and its consultant, SKM, reported that the high level of expenditure proposed results partly from a previous period of under-investment on the network (although SKM noted that the assets were generally in good condition). These factors could justify a higher-than-expected level of capex but, on the other hand, the question arises as to how quickly any previous shortfall should be redressed. We took account, in this context, of the methodological reservations expressed in this section of the report.

For these and other reasons our opinion is that EA's total capex programme for FY 2004-2014 should be reduced for the purpose of the coming determination and we have recommended accordingly in Section 4 of the report.

6.4 Actual v. Projected Opex for FY 1999-2003

Maintenance Practices

We received information on and reviewed EA's principal maintenance practices. We asked what percentage of work was carried out live and EA replied that all preventive maintenance on the overhead line network is done in-service and work that is corrective is done as a mixture of live- line and outage.

Operational Logistics and Practices

We obtained information on EA's operational logistics (stores, procurement, fleet and plant management, staff numbers and deployment) and practices (including shut-down management processes and out-sourcing), specifically whether the practices had been reviewed and improved recently. Also, whether its operational policies had been reviewed and improved recently. EA provided a comprehensive reply that indicated acceptable practices as far as the purpose of this review is concerned.

Asset Knowledge

We asked EA about the adequacy of its geographic information systems and other databases used for operation and maintenance purposes and for determining capex and renewal programmes. EA replied that it had spatial representation of all network assets for all regions. Other external databases such as its network asset management system technical information system and other systems are used in conjunction with the GIS for operations and maintenance purposes. It reported that the quality and timeliness of the GIS data is being improved continually.

Service Standards and Actions

We asked EA for details of its current service standards to judge their reasonableness and were satisfied that the performance measures cited in its submission to IPART Chapter F were in reasonable alignment with industry standards where practicable. We did not consider that there were any features in the information presented that would impinge inappropriately and materially on capex or opex for the purpose of this review.

Comparison of Actual and Projected Opex for FY1999-2003

We asked EA to provide details of its projected opex during the period FY 1999-2003 for comparison with its own 1998 projections and to identify the reasons for any major departures from the projections under the following headings, giving reasons (its responses are given in parenthesis):

(a) Opex incurred in relation to Y2K and full retail contestability (no response);

(b) Opex arising each year during the period as a direct result of the amalgamation of the DNSP with others (no response);

(c) Opex resulting from the need to comply with new statutory obligations that came into effect during the period and describe the nature of the obligations (EA gave a detailed response and indicated that their assessment of the additional costs incurred during the period was as follows:

Cost	Total value over the 1999 regulatory period ($ million)
Regulation 2001 – OH&S costs	22.44
Insurance – Post September 11 premium increases and HIH exposure	17.90
Additional tree trimming costs	49.00
Environmental costs	29.00
Y2K compliance	10.40
Privacy legislation	0.44
Total	**129.2**

(d) Opex resulting from non-network solutions and the extent to which it exceeded the projections (no response);

(e) The balance of the difference between projected and actual opex (no response).

Our opinion is that, based on the information made available to us and on our own assessment, we had no reason to judge any material component of EA's actual opex during the period FY 1999-2003 imprudent.

Table 17 summarises EA's opex data.

6.5 Opex Projections for FY 2004-2009

We received EA's projections of opex for the period FY 2004-2009. We also received the SKM on EA's O &M projections for FY 2004-2009 in which a detailed analysis of opex cost components was given. We noted SKM's view "that the capex and opex allowed for EA in the 1999 determination were significantly below the industry average". We also noted SKM's statement that their calculated opex assumed that capex on replacement and refurbishment works would be escalated from the current level of approximately $40 million p.a. at least to the levels recommended in SKM's November 2002 report on the assessment of capex – stage 2. We reviewed the opex benchmarking information in SKM's report on opex projections and have commented on it already in Section 5 of this report.

Our opinion is that, based on the information made available to us and on our own assessment, EA's requested increase in opex should not be accepted and we have recommended accordingly in Section 5 of the report.

Table 15: Network Fixed Asset Age Profiles (EA)

Asset category	Unit	Number of assets commissioned in the period																	
		Pre-1920	1920-1924	1925-1929	1930-1934	1935-1939	1940-1944	1945-1949	1950-1954	1955-1959	1960-1964	1965-1969	1970-1974	1975-1979	1980-1984	1985-1989	1990-1994	1995-1999	2000-2002
132 kV tower lines	km	-	-	-	-	-	-	-	-	55	108	163	13	28	8	6	1	-	-
132 kV pole lines	km	-	-	-	-	-	-	-	16	54	159	18	43	126	109	7	93	22	9
132 kV U/G cables	km	-	-	-	-	-	-	-	-	31	41	91	186	101	20	7	5	16	12
66 kV lines	km	-	-	-	91	-	-	-	31	6	23	13	-	147	80	30	14	5	18
66 kV U/G cables	km	-	-	-	-	-	-	-	-	-	-	0.14	-	-	-	-	0.36	-	-
33 kV lines	km	-	-	7	5	136	45	-	80	217	382	384	132	209	55	16	21	-	-
33 kV U/G cables	km	-	-	-	53	62	14	71	100	133	150	141	65	18	4	2	1	15	9
11/22 kV lines	km	4	9	24	24	64	58	134	259	586	1,044	1,590	1,728	1,273	1,187	816	658	528	224
11/22 kV U/G cables	km	-	137	137	137	127	30	98	157	246	471	570	638	884	511	275	351	448	506
SWER lines	km																		
LV lines	km	8	17	48	49	131	116	272	529	1,198	2,114	3,246	3,522	2,749	2,529	1,745	1,514	1,154	465
LV U/G cables	km	-	57	57	57	198	12	57	114	127	184	312	778	1,004	662	422	450	559	227
Distribution transformers	No	1	8	25	79	127	110	135	519	661	2,726	3,254	4,090	3,302	4,228	2,898	3,633	3,141	1,245
132 kV CBs	No	-	-	-	-	-	-	-	13	54	74	41	50	34	20	5	17	29	36
66 kV CBs	No	-	-	-	-	-	-	-	-	14	16	5	12	24	31	1	5	-	6
33 kV CBs	No	-	-	-	-	14	-	3	101	128	259	197	92	52	18	6	60	37	6
11/22 kV CBs	No	-	-	-	2	97	16	66	259	174	439	628	670	406	143	69	27	67	260
Other distribution switchgear (all voltages)	No																		
Service connections	No	581	5,061	6,613	7,838	24,821	10,507	27,662	40,708	82,477	127,629	184,595	231,815	211,121	175,386	108,953	96,783	87,793	34,412
Revenue meters & load control relays	No	-	-	-	-	52,646	80,955	91,140	88,770	131,478	171,692	244,286	226,514	259,537	355,884	316,436	339,302	315,910	165,198

Table 16: Capex (EA)

Energy Australia Capex		($1998 million)						($ nominal million) (note a/)						($2003 million)											
Fin yr ending 30 June ->	Notes	**Total**	1999	2000	2001	2002	2003	**Total**	1999	2000	2001	2002	2003	**Total**	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Basis ->		**98 Projn**	98 Projn	98 Projn	98 Projn	98 Projn	98 Projn	**Actual**	Actual	Actual	Actual	Actual	Est.	**Est.**	Est.	Est.	Est.	Est.	Est.	Est.	Est.	Est.	Est.	Est.	Est.
Replacement - end of life		**219**	20	35	45	51	66	**196**	15	49	58	36	38	**1,264**	36	103	108	92	108	116	144	142	145	148	121
Environ, safety, stat, other		**21**	3	3	5	5	6	**55**	7	7	4	9	29	**450**	29	41	40	43	40	43	43	43	43	43	43
Non-network capex		**97**	25	19	18	18	18	**144**	22	23	32	32	34	**390**	38	37	36	32	34	36	35	35	35	35	35
Total renewal / replacement		**337**	48	58	68	74	90	**395**	44	79	94	77	102	**2,104**	102	181	185	167	182	195	222	220	223	226	199
Growth (demand related)		**228**	55	40	41	43	50	**596**	74	93	138	151	140	**1,893**	148	184	177	173	158	150	202	180	161	175	185
Reliab. and qual. improvement		**68**	23	12	11	10	10	**50**	5	18	9	8	10	**224**	10	20	19	20	21	21	22	22	23	22	24
Sub-total		**632**	127	110	120	127	150	**1,042**	123	190	241	236	251	**4,221**	260	385	381	361	361	367	446	422	407	423	408
Possibly excluded services:																									
Capital contribution works	0%	**-**	-	-	-	-	-	**187**	25	63	35	31	33	**331**	31	30	30	30	30	30	30	30	30	30	30
Metering	46%	**25**	10	10	5	-	-	**50**	9	9	5	10	16	**132**	8	12	12	12	12	12	12	12	12	12	12
Public lighting	54%	**29**	1	7	7	7	7	**34**	13	7	6	5	4	**52**	5	5	5	5	5	5	5	5	5	5	5
Sub-total	100%	**54**	11	17	12	7	7	**271**	47	79	46	46	53	**515**	44	47	47	47	47	47	47	47	47	47	47
Other capex (Y2K and FRC)		**-**	-	-	-	-	-	**71**	-	43	14	11	2	**16**	2	1	1	1	1	1	1	1	1	1	1
Total		**687**	137	127	132	134	157	**1,383**	170	313	301	293	306	**4,752**	305	433	430	409	410	415	494	471	455	472	457
Actual as percentage of projected								202%	124%	247%	228%	219%	195%												
Actual as percentage of projected after deducting capital contrib. works and Other Capex								164%	106%	163%	191%	188%	173%												
Annual average expenditure projected for FY 2004-2014 (total of all capex)														**432**											

Figures have been rounded. Transmission-related expenditure is excluded.

Source: DNSP's submissions to Meritec Limited with adjustments by Meritec Limited where agreed with the DNSPs or where noted. The final adjustments and approvals are Meritec's opinion.

Interptetation: this table in its original form was prepared by Meritec Limited for inclusion in its review of capex and opex, 2003, and is valid only in the form in which it appears in their report. Reference should be made to the main text of the rep

a/ Impact of cost increases due to inflation, if any reported by the DNSP concerned, is discussed in the main text of the report. An automatic allowance for increases has NOT been included unless quantitative supporting evidence has been provided.

Table 17: Opex (EA)

Energy Australia Opex		($ nominal million)						($ nominal million)						($ 2003 million)					
Fin yr ending 30 June ->	**Total**	1999	2000	2001	2002	2003	**Total**	1999	2000	2001	2002	2003	**Total**	2004	2005	2006	2007	2008	2009
Basis ->	**98 Projn**	98 Projn	98 Projn	98 Projn	98 Projn	98 Projn	**Actual**	Actual	Actual	Actual	Actual	Est.	**Est.**	Est.	Est.	Est.	Est.	Est.	Est.
Network operation	**153**	30	30	31	31	32	**157**	26	29	28	38	35	**249**	38	41	42	42	43	42
Network maintenance - pole replacement	**20**	4	4	4	4	4	**22**	2	5	5	5	5	**43**	6	7	7	7	8	8
Network maintenance - reactive	**371**	72	75	75	75	73	**183**	-	43	45	45	50	**383**	56	62	66	66	67	66
Network maintenance - vegetation control	**0**	-	-	-	-	-	**74**	7	9	17	22	19	**119**	17	18	19	20	21	22
Network maintenance - other preventive	**0**	-	-	-	-	-	**78**	-	24	26	14	15	**154**	17	22	24	27	30	34
Other operating costs	**458**	83	85	91	96	103	**507**	173	41	66	134	92	**538**	97	96	94	90	84	78
Total	**1,002**	189	194	201	206	212	**1,021**	209	151	186	259	216	**1,486**	232	245	253	253	252	250
Average actual expenditure p.a. 1999-2003 ($m)	204																		
Actual, 1999-2003, as pct of projected	102%																		
Actual in 2003 as pct of actual in 1999	103%																		
Projected for 2004 as pct of projected for 2003	107%																		
Projected for 2009 as pct of projected for 2004	108%																		
Opex for Possibly Excluded Services																			
Asociated with customer-funded connections	**0**	-	-	-	-	-	**0**	-	-	-	-	-	**0**	-	-	-	-	-	-
Associated with cust-specific ancillary services	**0**	-	-	-	-	-	**18**	-	4	5	5	5	**28**	5	5	5	5	5	5
Meter maintenance	**0**	-	-	-	-	-	**9**	-	2	2	3	2	**12**	2	2	2	2	2	2
Metering services	**42**	7	8	8	9	10	**50**	-	12	12	15	11	**76**	11	13	13	13	13	13
Public lighting	**45**	9	9	9	9	9	**44**	9	9	9	8	9	**76**	10	11	12	13	14	15
Total	**87**	16	17	17	18	19	**121**	9	27	28	30	27	**193**	28	31	32	33	34	35
Average actual expenditure p.a. 1999-2003 ($m)	24																		
Actual in 2003 as pct of actual in 1999	315%																		
Projected for 2004 as pct of projected for 2003	104%																		
Projected for 2009 as pct of projected for 2004	124%																		
Other Opex																			
Projected Y2K	**23**	14	9	-	-	-	**10**	-	10	0	-	-	**0**	-	-	-	-	-	-
Projected FRC	**50**	-	6	17	16	11	**41**	-	2	13	12	14	**84**	14	14	14	14	14	14
Total Opex																			
Regulated services	**1,002**	189	194	201	206	212	**1,021**	209	151	186	259	216	**1,486**	232	245	253	253	252	250
Posibly excluded services	**87**	16	17	17	18	19	**121**	9	27	28	30	27	**193**	28	31	32	33	34	35
Other opex	**73**	14	15	17	16	11	**51**	0	12	13	12	14	**84**	14	14	14	14	14	14
Total	**1,162**	218	225	235	240	243	**1,194**	218	190	228	300	258	**1,763**	274	290	299	300	301	300
Average actual expenditure p.a. 1999-2003 ($m)	239																		
Actual in 2003 as pct of actual in 1999	118%																		
Projected for 2004 as pct of projected for 2003	106%																		
Projected for 2009 as pct of projected for 2004	109%																		

Figures are rounded. Line costs and transmission-related expenditures are excluded.
Source: DNSP's submissions to Meritec Limited with adjustments by Meritec Limited where agreed with the DNSPs or where noted. The final adjustments and approvals are Meritec's opinion.
Interptetation: this table in its original form was prepared by Meritec Limited for inclusion in its review of capex and opex, 2003, and is valid only in the form in which it appears in their report. Reference should be made to the main text of the rep

7.0 Assessment – Integral Energy

7.1 General

General Information and Documentation

The following general information and documentation was obtained from IE and reviewed:

(a) Recent annual reports;
(b) Organisation chart, employee numbers and contracted services (IE currently contracts out IT management, vegetation management, line inspections, civil design and construction for major projects and some other non-core activities);
(c) Corporate plan and related policy documents;
(d) Asset management plan and related documents;
(e) Long-term network development plan and related policy documents;
(f) Selected procurement and construction specifications;
(g) Recent network performance reports;
(h) A sample of the network single-line diagrams and maps.

We were given a summary of assets in service at 30 June 2002 and their age profile. A summary of the latter is reproduced in Table 18.

We obtained and reviewed general statistics and system performance data as summarised in Section 3 of the report.

We received and reviewed sub-transmission network utilisation data as presented in IE's Transmission Network Planning Review 2003-2012, Distribution Network Status Report 2001/2002 (which gives details of the 11kV feeder loads that are in excess of the design requirements for IE's network) and its Annual Planning Statement 2003. These reports provide information on network constraints and proposed remedial actions. We received and briefly reviewed information on zone substation utilisation.

Demand Forecast

We received information from IE on its forecasting methodology and its forecasts. We noted that its energy forecasts had been developed using methodologies appropriate to the relevant factors driving growth. The residential forecast used an end-use analysis by forecasting energy consumption at the appliance level (i.e. by projecting number of end-use customers, appliance penetration and energy efficiency at the end-use level) but IE noted that the load was driven by economic and demographic factors in the longer term and that the forecast used the econometric analysis of variables such as NSW Gross State Product for the IE distribution area, household income, retail electricity price, mortgage interest rate, population size, number of households and average household size. The high, medium and low growth scenarios were based on three economic scenarios (defined as High Case, Medium Case and Low Case); these took account of global, Australian and state economic factors. Consumption was normalised for weather and assumes average weather conditions based on historical data.

We were advised that IE had retained Trowbridge Deloitte to review the forecast and we received a copy of their report dated January 2003. They concur with our opinion that IE's medium scenario is 'a reasonable proxy for the most likely level of growth in Integral's area over the forecast period'.

We therefore considered IE's medium-growth forecast to be the appropriate choice for the purpose of our review.

Demand-Side Management

We were advised that approximately 1,556 MW of load was controlled by ripple control systems and time clocks. IE reported that it also had agreements for demand reductions on request.

IE provided us with a copy of its *Demand side management 2002-03* plan for future investigation areas and noted that programmes currently implemented or being considered actively include Seven Hills load shifting, Wetherill Park load shedding and Castle Hill load reduction and other works. A more detailed discussion is presented in Section 7.3.

We concluded, however, that demand management prospects in IE's area are not likely to have a material impact on their capex requirements within the period FY 2004-2009 but have the propensity to make a meaningful impact in the future.

Distributed Generation and Other Non-Network Solutions

IE provided us with a copy of its *Distributed generation table* as at 1 February 2003 for embedded generation within its area. It said it relied on distributed generation for network support in two locations: Appin/Tower and Smithfield. The former supplies up to 94 MW into the local area reducing to 65 MW under network contingency conditions and 50 MW on high pollution days. This generation is assisting to defer augmentation of Nepean Transmission Substation and several 66kV feeders. The augmentation of two 66kV feeders at a value of $4 million is being deferred indefinitely while re-building of a third feeder valued at $1.8 million is being deferred until 2009. The augmentation of Nepean Transmission Substation, valued at $6 million, is also being deferred indefinitely from 2001. The 20-year NPV annual saving this capital deferral equates to is $300,000. Sithe Generation supplies 160MW and 60MVAr onto the 33kV bus bar at Guildford Transmission Substation. The normal static support arrangement at Guildford Transmission Substation is for only 20MVAr with Sithe supplying the remaining MVAr needs. This arrangement is deferring the need to augment/rebuild Guildford

Transmission Substation valued at $10 million. The 20-year NPV annual saving this capital deferral equates to is $310,000.

Future generation prospects are discussed in Section 7.3 under the sub-heading *Capex projections.*

We concluded that embedded generation prospects in IE's area within the period FY 2004-2009 are not material in terms of this review.

Independent Forecast

We were provided with data to prepare our own forecast of future demand should we consider that step necessary but on review of IE's own forecast, noting its comprehensiveness, we concluded that (a) we could not improve on the accuracy of IE's own forecast with the data available to us; and (b) IE's medium forecast was in our opinion reasonable for the purpose of this review.

7.2 Actual v. Projected Capex for FY 1999-2003

Definition of Capex

We asked IE to confirm its definition of capex with reference to the NSW Treasury's *Guidelines for capitalisation of expenditure in the NSW public sector, June 2000* and were advised that its policies and procedures were aligned with the Guidelines.

Actual v. Projected Capex

IE was asked to enter its actual capex in the years FY1999-2003 under certain prescribed headings in the template together with its capex projections made at the time of the 1998 capex review. IE reported that assumptions had been made to align its historical expenditure with the requested reporting categories and that some inaccuracies may have resulted. We did not consider them likely to be material.

IE was asked to explain the reasons for changes in expenditure under the headings listed below (its responses are given in parenthesis):

(a) Changes in projected or actual load or in load patterns during the period (IE provided a detailed response which identified the causes and impacts of increased capex: (i) higher-than-expected load growth in areas of Western Sydney particularly due to the installation of greater numbers of residential and commercial air conditioners combined with movement of demand to summer months and an increase in after-diversity maximum demand leading to the need for network reinforcement, the impact of these factors being the need to arrest declining security of supply at the zone substation and sub-transmission level at an estimated cost of $115 million over the period FY 1999-2004 as shown in the table below [23];

Nominal $ million	FY 1999	FY 2000	FY 2001	FY 2002	FY 2003	FY 2004	Total 99-03	Total 99-04
1999 Determination allowance	6.1	15.4	8.7	3.7	13.8	11.9	47.7	59.6
Actual/ Forecast Expenditure	4.1	13.9	30.2	28.4	38.1	59.8	114.7	174.5
Increase	(2.0)	(1.5)	21.6	24.7	24.3	47.9	67.1	115.0

(ii) power factor improvement including the installation of switched capacitor banks at 72 zone substations was instigated, resulting in previously unplanned expenditure of $22 million during the regulatory period (included in the total in (i) above); and (iii) additional costs of connecting customers estimated to have cost an additional $43 million in capex over the period due to greater-than-expected numbers spurred partly by the Federal Government's First Home Owners Grant and exacerbated by the need for upstream reinforcements in the network, the estimated additional cost being $43 million as shown in the following table);

Nominal $ million	FY 1999	FY 2000	FY 2001	FY 2002	FY 2003	FY 2004	Total 99-03	Total 99-04
1999 Determination allowance	17.2	13.1	13.6	14.4	13.7	15.6	72.0	87.6
Actual/ Forecast Expenditure	15.7	20.6	13.6	24.2	27.8	28.8	101.9	130.7
Additional cost	(1.6)	7.5	0.0	9.8	14.1	13.2	29.9	43.1

(b) Changes in installed unit costs from those assumed in its 1998 projections (IE replied that it did not consider these changes to be a major driver of the variation in its capex over the period);

(c) The need for compliance with new statutory obligations, if any, introduced during the period (IE provided a detailed response identifying the following costs: increased expectations of government, the company and community in relation to safety and security ($2 million); increased community awareness of the environment and the impact of waste water and oil spillage on it and corresponding ($4.8 million); increased community awareness of noise pollution issues supported by

[23] IE made minor variations after these estimates were prepared but the changes were not material.

legislation ($5.5 million); the removal of PCBs ($880,000); under-frequency load shedding equipment to meet NEC requirements ($930,000); and a programme to monitor power quality costing $650,000 that we did not consider to have been the result of new requirements);

(d) The advancement or deferral of expenditures during the period other than for reasons already listed (IE gave a detailed reply indicating that additional refurbishment expenditure of $34.7 million had been required notwithstanding IPART's reduction in its proposed renewal expenditure in the 1999 determination by $12 million p.a. The variances are shown in the following table:[24]

Nominal $ million	FY 1999	FY 2000	FY 2001	FY 2002	FY 2003	FY 2004	Total 99-03	Total 99-04
IE submission of 1998	30.2	49.4	48.3	36.9	36.1	33.5	200.9	234.5
Adjustment by IPART	(12.2)	(12.6)	(13.3)	(13.7)	(14.1)	(14.4)	(65.8)	(80.3)
IPART allowance in 1999 Determination	18.0	36.8	35.0	23.2	22.1	19.1	135.1	154.2
Actual expenditure	9.6	20.7	29.2	38.0	31.9	59.6	129.4	188.9
Overrun from IE submission	(20.6)	(28.7)	(19.2)	1.1	(4.2)	26.0	(71.6)	(45.6)
Overrun from IPART allowance	(8.4)	(16.2)	(5.8)	14.8	9.9	40.4	(5.7)	34.7

(e) Adoption of new policies, planning criteria or designs following its amalgamation if any with other DNSPs (IE replied that this was not applicable);

(f) Planning or budgeting errors (IE replied that it did not consider that there were any significant errors due to these reasons);

(g) The extent to which Y2K or full retail contestability costs added to expenditure (in reply, IE noted that no amounts were projected in 1998 for Y2K or FRC and gave details of the amounts expended, claimed and approved as follows:

24 IE noted that the definition of renewal for this table is as used in the 1999 determination but that in its submission for the 2004 determination additional categories have been introduced which reduced the amount remaining in the renewal category. Therefore the above table does not reconcile with their renewal entry in the forward projections.

	FY 2001	FY 2002	FY 2003 Forecast	Total
Amount allowed for FRC by IPART	1,641,828	18,531,867		20,173,695
Actual FRC costs incurred by Integral	1,172,907	15,632,131	2,872,048	19,677,086
Difference between allowed and actual	468,921	2,899,736	-2,872,048	496,609
Additional Type 5 Call Centre and Middleware costs	1,744,307	2,872,830	192,057	4,809,193
Total FRC + associated costs	2,917,213	18,504,961	3,064,105	24,486,279

IE noted that the Total of FRC and associated costs for FY 2002 is larger than those shown in the template it completed for us because the template reflects the regulatory accounts which only captured the direct costs associated with the FRC business unit. There were some FRC projects funded from Metering and IT for budgetary reasons which are therefore not contained in the regulatory accounts/template but are shown above);

(h) The extent to which changes in its policies for overhead cost allocation increased the cost of capital works (IE provided a detailed response to this item noting that its treatment of capitalised overheads had remained unchanged since the 1999 determination but that at the time of the 1999 determination it had used transfer pricing to pass costs between business units and that these costs had included a component to reflect the cost of non-network capital. With the exception of the customer service system and integrated asset information management system projects non-network capex (IT, plant and vehicles, buildings, etc) was not included in its 1998 capex projections: instead, depreciation charges relating to the expenditures of this expenditure was reflected to the Network business as an internal charge and was thus included in overheads in the opex figures put forward at the time. IE said that from 1 July 2000 it had moved away from this model and so the non-network capex had now been included in the regulatory accounts. This treatment had increased the capex from a regulatory perspective. For this review IE chose to treat non-network capex as if it had been reported as such from the start of the [present] regulatory period and corresponding reductions have been made to its opex. The increase in IE's capex as a result of the non-network capex being incorporated as such is calculated by IE to be $162.6 million (nominal) excluding capex on CSS and IAIMS systems for the period FY 2000-2004. Detail regarding the nature of this adjustment was provided to us and to IPART);

(i) The extent to which non-network solutions and demand-side management measures reduced capex (IE replied that it considered itself as an industry leader in seeking out and applying demand management initiatives to its growth-related capital planning process, noting that it had convened and led the DM code of practice working group inaugurated in 1998 and that it had taken a leadership role in continuing to develop the existing code in conjunction with stakeholders. It said it had been pro-active in encouraging demand side management initiatives to assist with the capacity of the network where constraints exist and that these initiatives had involved both market-based and traditional network planning approaches. It said it had consistently recorded good results in its demand management activities and that programmes had been implemented and maintained during the current regulatory period and that $14.2 million of capex has been or will be deferred at a cost of $750,000 achieving a 20-year NPV saving (total avoided network cost) of $1.7 million. It said that these initiatives had included the contracting of load reduction programmes at times of network constraint with large customers, fuel substitution initiatives and the management of off-peak load; and trials to develop innovative control of air-conditioning units at times of network constraint; and that another example of a DM programme was the Seven Hills load curtailment programme where almost $2 million of capex had been deferred for five years at a cost of $60,000 producing a saving of $270,000. It provided details of these programmes and noted that the Parramatta CBD programme was expected to commence in FY 2004 but has not been included as agreement is yet to be finalised.);

(j) Other factors, for example: the net cost after insurance recoveries of remedying damage (IE referred to un-planned projects arising for unforeseen emergency situations such as fire or flood and gave details of around $5.6 million of expenditure).

We discussed these responses with IE and obtained details of the expenditures made including reasons for the material items.

We noted that IE's capex covered the full range of network and non-network expenses including the replacement of obsolete gear, installation of new equipment to improve voltage conditions on the network and to meet load growth, new customer connections, metering and load control equipment, the modification of mobile plant to comply with current requirements and other items. We discussed the scheduled expenditures with IE's staff and concluded that the expenditures were reasonable for the purpose of this review.

Our opinion is that, based on the information made available to us and on our own assessment, notwithstanding the comments made above, we had no reason to judge any material component of IE's actual capex during the period FY 1999-2003 imprudent.

Table 19 summarises IE's capex data.

7.3 Capex Projections for FY 2004-2014

Network Planning Criteria

We obtained from IE information on its documented network planning criteria for sub-transmission systems, high voltage distribution systems and low voltage distribution systems. We also asked for and obtained information on the length of planning period assumed in its long-term network planning process. We asked when the criteria had last been reviewed, whether the security of supply criteria were deterministic, probabilistic or both, and what plant rating criteria were applied. IE provided us with comprehensive information in response. We considered the criteria reasonable.

Optimality of Design and Construction Practices

We asked to what extent cable, conductor and equipment sizes, circuit designs and procurement were optimal. IE said that it kept its designs under review in light of changing external factors and gave details of its approach to optimisation of the main network elements.

We considered that the designs assumed were reasonable.

Unit Installation Costs and Standard Lives

We asked IE to indicate whether its unit installed costs and standard lives assumed when preparing capex projections were in accordance with Appendix C of the NSW Treasury's Guidelines (there is no requirement for them to be if the alternative approach used is sound). IE replied that it used its own estimates and it provided details of the main differences. We noted that some of its costs were lower and others were significantly higher. Reasons were given for the main departures. IE provided an explanation of the derivation of its own rates and noted that a significant proportion of network capex is delivered by the market through competitive bidding of materials and equipment or as contestable work.

We accepted the explanations and the accompanying cost estimates as reasonable for the purpose of this review.

Methodology for Determining Replacement Capex

We asked IE to outline its approach to determining replacement capex and received a detailed reply referring us amongst other things to its asset renewal policy document. We noted: (a) that asset age is used only as a surrogate for determining end-of-life in the absence of condition, performance or other data; (b) a detailed schedule of asset categories and their replacement criteria was provided; (c) a model prepared by PB Associates was used to test the assumptions of replacement expenditure and showed agreement with IE's own projections (details of the assumptions made in the modelling were given to us); (d) asset condition assessments had been made at various times since 1995 , particularly since 1996 and the data had been combined into the asset management plan in 1999; (e) issues identified in the condition assessments included: power transformers with high levels of moisture in the oil and oil acidity levels, elevated levels of dissolved gases, oil leaks, poor tap-changer reliability; circuit breakers, in particular certain132kV minimum oil and 33kV minimum oil and bulk oil breakers and 11kV outdoor breakers with high maintenance costs and poor performance (unacceptable reliability); current transformers in poor condition, high DLA readings and with destructive failure modes; station batteries with type fault or age-related failure requiring a wholesale replacement programme; surge arresters with destructive failure modes particularly old silicon carbide types, those without pressure relief venting and those supporting bus bars; corrosion of outdoor bus bar supports in coastal areas; a requirement to address both the leaks and the containment of spilled oil; inadequate security of sites from fire and intrusion; vegetation management around the sites; voltage regulation equipment becoming unreliable due to age and condition; 132kV steel tower lines, particularly in the coastal areas, experiencing corrosion-related failure of insulator strings, corrosion of earth-wires, conductors, steel fittings, tower structure and grillage foundations, condition of safety signage, anti-climbing devices and access tracks; 132kV, 66kV and 33kV wooden pole lines, particularly 33kV lines in the coastal regions in poor condition with high incidents of cross-arm failure, flash-over of insulators and pole-top fires; strategic 132kV paper-oil cables with unknown condition requiring further investigation and monitoring of oil quality trends; 33kV gas insulated cables supplying commercial areas in Parramatta and Wollongong with significant levels of gas leakage, low serving resistance measurements and subsequently at high risk of sheath corrosion related failure; early generation 66kV XLPE cables with water-treeing problems and consequently poor reliability; type-fault and resulting destructive failure of KRONE 11kV epoxy switchgear; poor condition of pole substation drop-out fuse assemblies, polythene droppers and lugs, surge arresters and transformer tanks (corrosion and leaks); poor condition of the older "cottage" style ground substations and twin-pole pole substations; need for management of wood-pole asset replacements; pole-top decay in particular areas within Integral's supply area; corrosion of steel conductors; annealing of steel and aluminium conductors due to the occurrence of un-cleared faults; poor condition of air-break switches in the coastal areas, low voltage pillars corroded of street light columns; poor condition and destructive failure mode of metal encased 11kV cable terminations; poor condition and failure history of low voltage “consac” cables; SCADA systems performing poorly due to failures, lack of availability for spare parts combined with the lack of required functionality; and need for replacement of some protection systems.

Our opinion was that the capex replacement needs had been assessed thoroughly although we expressed concern about the magnitude of expenditure proposed. In this context we had similar concerns to those expressed in relation to EA. We noted that IE placed weight in its reduced risk scenario in particular on arresting the increasing age of its network in aggregate. We noted also that the conclusions of the modelling undertaken are reliant on the input parameters assumed. We recognised that the modelling was a possible approach to resolving the uncertainty surrounding the optimal capex-opex trade-off but we had reservations that it might not necessarily lead to a reasonable outcome overall because of uncertainty about the correctness of the parameters assumed. [25]

Impact of Statutory Obligations on Capex

We asked IE to estimate the impact on capex of statutory obligations including but not limited to safety, environmental protection and quality of supply. IE listed the same or similar factors as the other DNSPs and indicated a magnitude of expenditure under this heading of $18.6 million. We noted the impacts arising from these reasons and considered the estimates reasonable for the purpose of this review.

Capex Evaluation and Approval Processes

We reviewed the capex evaluation and approval processes followed from project identification to approval and considered them appropriate for the purpose of this review.

Capex Projections

We received IE’s projections of capex for the period FY 2004-2014. We were given a detailed schedule of line items making up the projected expenditures and noted that, as in the case of past capex, the expenditures covered the full range of network and non-network expenses including the replacement of obsolete gear, installation of new equipment to improve voltage conditions on the network and to meet load growth, new customer connections, metering and load control equipment, the modification of mobile plant to comply with current requirements and other items. We noted the significant impact of a shift to summer loading.

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[25] See also Sections 2.10 and 2.18.

We asked for and received supplementary information on certain major items of capex, in particular the transmission and sub-transmission system works in the replacement programme including those at Springhill and the new substations in the growth capex programme including those at Wetherill Park, East Liverpool and Parramatta. Although we could not tell with certainty that the chosen options were the most economic or the proposed timing was the most appropriate or the cost estimates were accurate we did conclude that (a) with further study, would probably reach the same or similar conclusions to IE; and (b) there did not appear to be any material non-network solutions that would address the system problems that were the focus of the projects.

We discussed the programme with IE's planning engineers, receiving explanations in response to our questions.

We noted that we had ourselves inspected some of the facilities in question during previous work for IPART and IE's pre-merger entities and were generally familiar with the situation and the condition of the network.

Notwithstanding the comments made we were satisfied, on the basis of the information made available to us, that the individual projects were justifiable for the purpose of this review.

We were, however, concerned about the magnitude of the capex programme as a whole. We noted IE's points about the increasing average age of its assets and that growth in its service area is projected to be the highest of the DNSPs (see Table 5). These factors could justify a higher-than-expected level of capex but, on the other hand, the question arises as to how quickly any previous shortfall should be redressed. We took account, in this context, of the methodological reservations expressed in this section of the report.

For these and other reasons our opinion is that IE's total capex programme for FY 2004-2014 should be reduced for the purpose of the coming determination and we have recommended accordingly in Section 4 of the report.

7.4 Actual v. Projected Opex for FY 1999-2003

Maintenance Practices

We received information on and reviewed IE's principal maintenance practices. We asked what percentage of work was carried out live and IE replied that about 25 - 35% of work involving a potential outage to customers is carried out live.

Operational Logistics and Practices

We obtained information on IE's operational logistics (stores, procurement, fleet and plant management, staff numbers and deployment) and practices (including shut-down management processes and out-sourcing), specifically whether the practices had been reviewed and improved. Also, whether its operational policies had been reviewed and improved recently. IE provided a comprehensive reply that indicated acceptable practices as far as the purpose of this review is concerned.

Asset Knowledge

We asked IE about the adequacy of its geographic information systems and other databases used for operation and maintenance purposes and for determining capex and renewal programmes. IE outlined the databases it used and commented that, as far as their accuracy is concerned, an audit had been conducted in 1999 of the 35,000 transformers and that a field check of 1% of asset data is planned to establish the quantity of non-conformance of distribution and transmission data and provide a further level of comfort on which further assessments of all data could be made. It expressed the view that its level of asset knowledge is sufficient for decision-making purposes.

Cost Efficiencies Arising from Integration

IE did not consider this applicable.

Service Standards and Actions

We asked IE for details of its current service standards. We were satisfied that the performance measures were in reasonable alignment with industry standards where practicable and we did not consider that there were any features in the information presented that would impinge inappropriately and materially on capex or opex for the purpose of this review.

Comparison of Actual and Projected Opex for FY1999-2003

We asked IE to provide details of its projected opex during the period FY 1999-2003 for comparison with its 1998 projections and to identify the reasons for any major departures from the projections under the following headings, giving reasons (its responses are given in parenthesis):

(a) Opex incurred in relation to Y2K and full retail contestability (IE replied that Y2K costs of $4.96 million had been notified to IPART after they were incurred, FRC costs were notified to IPART mid-way through the project's life and so consisted of both actual costs and projections, and FRC operating costs incurred by IE up to the end of FY 2003 were $10.5 million.);

(b) Opex arising each year during the period as a direct result of the amalgamation of the DNSP with others (IE indicated that opex relating to the amalgamation of Prospect and Illawarra Electricity were incurred in the years prior to FY 1999);

(c) Opex resulting from the need to comply with new statutory obligations that came into effect during the period and describe the nature of the obligations (IE indicated that the main statutory changes and their estimated cost impact were: Electricity Supply (General) Amendment Regulation 1998 (NSW) - estimated cost of setting up the contracts and publishing the guaranteed service standards was $1.2 million ; GST - costs of preparing for its introduction were approximately $4.5 million over the period FY 2000-2001 and the ongoing cost of complying with the legislation is approximately $0.3 million p.a. for FY 2001 onwards; OH&S Regulation 2001 - forecast costs (viz: training, project teams, consultancies, communication and processes/procedure set-up for works method statements etc) are estimated at $0.7 million p.a. in FY 2003 and FY 2004; other items totalling an estimated impact of $3.3 million over the period FY 1999-2003);

(d) Opex resulting from non-network solutions and the extent to which it exceeded the projections (costs totalling $0.8 million were identified);

(e) The balance of the difference between projected and actual opex (IE identified the abnormal items in the following table in addition to those reported above).

Abnormal Items not allowed for in 1998	FY 1999	FY 2000	FY 2001	FY 2002	FY 2003	Total
Customer service obligations and other costs incorrectly booked to regulated networks operating results	0	13.4	1.4	0	0	14.8
Adjustments to superannuation provision as a result of diminution of defined benefits scheme – driven by recent corporate collapses and Sept 11incident	0	0	8.8	11.6	10.8	31.2
Additional security costs as a result of the increased threat of terrorism	0	0	0	0	2.3	2.3
Real wage growth including impact of wages growth on employee entitlements	3.3	3.8	4.0	1.6	8.1	20.8
Increase in self-insurance/insurance costs	0	0	4.6	5.1	7.9	17.6
Total ($ million)	8.0	19.9	24.1	21.6	33.1	106.7

We discussed these responses with IE.

Our opinion is that, based on the information made available to us and on our own assessment, we had no reason to judge any material component of IE's actual opex during the period FY 1999-2003 imprudent.

Table 20 summarises IE's opex data.

7.5 Opex Projections for FY 2004-2009

We received IE's projections of opex for the period FY 2004-2009 and discussed them with IE's staff including the reasons for the movements in total opex from year to year and particularly the movement from FY 2003 to FY 2004. IE noted that its opex is projected to increase from $202.1 million in FY 2003 to $215.4 million in FY 2004 and that the main components of the increase are: (a) real wage growth of $3.4 million in FY 2004 driven by the 5% award wage growth progressively paid during FY 2003 (viz: 3% in December 2002 and 2% in May 2003) plus the 5% increase to be paid in December 2003 (total impact $3.4 million); remediation of depot sites and asbestos panel changes from FY 2004 onwards (total impact $2.4 million); additional expenditure to meet OH&S safety management system/safety work method statement requirements (impact of $3.8 million on FY 2004 compared with $0.5 million in FY 2003); an increased expenditure on IT in FY 2004 to cater for additional IAIMS licence costs, legal/consultancy advice and duplication of support as part of the new outsource provider tender process and pass-over (total impact $3.8 million in FY 2004); an additional $1.8 million in FY 2004 to meet the requirements of the network strategy on top of the $3.6 million allowed for in FY 2003 to cater for growth and increased defect resolution rates continuing throughout the period; and an increase of $1 million in FY 2004 in OLI/GLI costs to cater for new contracts and bushfire management costs. We noted that these changes add to more than the opex increase from FY 2003 to FY 2004.

IE advised us that it considered the FY 2004 opex projection to be an exception and that opex projected for FY 2005 returns to $202 million and increases only marginally from that level over the remainder of the coming regulatory period. It says the reduction from FY 2004 to FY 2005 is due to projected reductions in superannuation and insurance costs.

We concluded that IE's opex projections for the period FY2004-2009 were reasonable for the purpose of this review, without adjustment. By that we mean that the programme constitutes, as best we are able to judge, an efficient programme for the purpose of this review.

Table 18: Network Fixed Asset Age Profiles (IE)

Asset category	Unit	Number of assets commissioned in the period																	
		Pre-1921	1921-1925	1926-1930	1931-1935	1936-1940	1941-1945	1946-1950	1951-1955	1956-1960	1961-1965	1966-1970	1971-1975	1976-1980	1981-1985	1986-1990	1991-1995	1996-2000	2001-2002
132 kV tower lines	km	0.0	0.0	0.0	0.0	9.1	0.0	165.7	57.2	9.4	126.1	176.3	2.3	4.0	2.7	0.0	0.0	6.7	0.0
132 kV pole lines	km	0.0	0.0	0.0	0.0	70.0	0.0	0.0	102.4	0.0	173.2	0.8	15.7	2.2	46.8	145.6	78.6	5.5	0.0
132 kV U/G cables	km	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.8	0.0	0.0	21.3	0.8	0.0	7.3	6.7	0.0
66 kV lines	km	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	24.9	63.7	2.8	11.1	49.9	202.2	85.9	33.2	27.7	19.4
66 kV U/G cables	km	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.4	3.1	7.6	1.0	0.0	1.0
33 kV lines	km	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.3	51.3	180.6	299.6	221.7	158.0	291.4	63.6	63.6	123.1	34.9
33 kV U/G cables	km	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.7	1.2	1.9	21.9	29.7	21.5	17.5	6.9	7.2
11/22 kV lines	km	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	238.6	336.5	1,266.6	1,425.7	746.5	3,286	1,083	661	667.0	403.8
11/22 kV U/G cables	km	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.7	8.0	21.2	47.6	230.1	277.1	478.5	400.7	307.5	383.6	211.2
SWER lines	km	0.0	0.0	0.0	0.0	0.0	1.2	2.5	0.0	0.0	12.3	2.5	17.2	43.2	73.7	139.9	56.5	111.8	6.1
LV lines	km	0.0	0.0	0.0	0.0	0.0	15	229	1,334	3,063	2,794	1,106	303	198	214	354	566	275	97.5
LV U/G cables	km	0.0	0.0	0.0	0.0	0.0	0.0	0.9	4.5	21.6	57.4	129.0	622.9	750.3	1,296	1,085	832.6	1,039	571.8
Distribution tfmrs	No	0	0	0	0	8	3	95	89	480	1,579	2,454	2,391	3,070	4,426	3,674	2,695	2,922	1,544
132 kV CBs	No	0	0	0	0	0	0	0	0	25	15	7	10	20	15	13	11	42	4
66 kV CBs	No	0	0	0	0	0	0	0	0	7	21	0	4	13	55	28	10	8	5
33 kV CBs	No	0	0	0	0	0	0	0	5	20	84	144	101	80	152	29	31	60	17
11/22 kV CBs	No	0	0	0	0	0	1	2	0	40	63	209	245	150	584	267	144	181	70
Other dist switchgear	No	0	0	0	0	0	56	147	780	1,052	4,612	7,426	4,509	12,310	17,900	13,335	8,274	9,626	1,984
Service connections	No	0	0	0	0	0	0	238	5,472	7,059	30,164	52,421	32,288	99,259	169,587	102,372	79,558	82,338	30,805
Meters and relays	No	0	0	0	2	850	6	80	2	379	5,026	84,084	143,850	169,675	279,582	284,708	283,660	302,041	58,548

Table 19: Capex (IE)

Integral Energy Capex — ($1998 million) — ($ nominal million) (note a/)

Fin yr ending 30 June -> / Basis ->	Notes	**Total 98 Projn**	1999 98 Projn	2000 98 Projn	2001 98 Projn	2002 98 Projn	2003 98 Projn	**Total Actual**	1999 Actual	2000 Actual	2001 Actual	2002 Actual	2003 Est.
Replacement - end of life		**189**	31	48	44	33	32	**107**	8	17	28	35	19
Environ, safety, stat, other		**1**	-	0	0	0	-	**14**	1	3	3	2	6
Non-network capex		**44**	16	18	5	5	-	**187**	55	28	16	45	43
Total renewal / replacement		**233**	46	66	50	39	32	**308**	64	47	46	83	68
Growth (demand related)		**133**	27	32	25	21	28	**244**	21	38	46	56	83
Reliab. and qual. improvement		**5**	1	1	1	1	1	**12**	1	1	1	1	7
Sub-total		**371**	74	99	76	61	61	**563**	86	87	93	140	158
Possibly excluded services:													
Capital contribution works	0%	**-**	-	-	-	-	-	**131**	18	23	25	30	35
Metering	54%	**35**	6	7	8	8	8	**16**	3	3	3	3	5
Public lighting	46%	**30**	7	6	6	6	6	**40**	10	9	6	8	5
Sub-total	100%	**66**	13	13	13	13	14	**187**	32	36	34	41	44
Other capex (Y2K and FRC)		**-**	-	-	-	-	-	**28**	5	-	3	16	3
Total		**437**	87	112	89	74	75	**778**	123	122	130	197	206
Actual as percentage of projected								178%	142%	109%	145%	268%	274%
Actual as percentage of projected after deducting capital contrib. works and Other Capex								142%	115%	88%	114%	205%	224%

($2003 million)

Fin yr ending 30 June -> / Basis ->	**Total Est.**	2004 Est.	2005 Est.	2006 Est.	2007 Est.	2008 Est.	2009 Est.	2010 Est.	2011 Est.	2012 Est.	2013 Est.	2014 Est.
Replacement - end of life	**939**	40	88	80	68	78	89	98	98	88	106	106
Environ, safety, stat, other	**39**	8	7	6	4	2	2	2	2	2	2	2
Non-network capex	**194**	53	30	26	20	20	21	24	-	-	-	-
Total renewal / replacement	**1,172**	102	124	112	91	100	113	124	100	90	108	108
Growth (demand related)	**1,178**	99	118	115	111	117	108	115	111	100	93	93
Reliab. and qual. improvement	**177**	12	20	22	21	22	20	12	13	12	11	11
Sub-total	**2,528**	214	262	249	224	239	241	252	224	201	212	212
Possibly excluded services:												
Capital contribution works	**403**	31	32	33	34	35	37	38	39	40	41	42
Metering	**90**	6	7	8	8	9	9	10	8	8	8	8
Public lighting	**65**	5	6	6	6	6	6	6	6	6	6	6
Sub-total	**557**	43	45	47	48	50	52	54	53	54	55	56
Other capex (Y2K and FRC)	**-**	-	-	-	-	-	-	-	-	-	-	-
Total	**3,085**	256	307	296	272	289	293	306	276	255	267	268
Annual average expenditure projected for FY 2004-2014 (total of all capex)	**280**											

Figures have been rounded.   Transmission-related expenditure is excluded.
Source: DNSP's submissions to Meritec Limited with adjustments by Meritec Limited where agreed with the DNSPs or where noted. The final adjustments and approvals are Meritec's opinion.
Interptetation: this table in its original form was prepared by Meritec Limited for inclusion in its review of capex and opex, 2003, and is valid only in the form in which it appears in their report. Reference should be made to the main text of the rep
a/ Impact of cost increases due to inflation, if any reported by the DNSP concerned, is discussed in the main text of the report. An automatic allowance for increases has NOT been included unless quantitative supporting evidence has been provided.

Table 20: Opex (IE)

Integral Energy Opex		($ nominal million)					($ nominal million)						($ 2003 million)								
Fin yr ending 30 June -> Basis ->	**Total** **98 Projn**	1999 98 Projn	2000 98 Projn	2001 98 Projn	2002 98 Projn	2003 98 Projn	**Total** **Actual**	1999 Actual	2000 Actual	2001 Actual	2002 Actual	2003 Est.	**Total** **Est.**	2004 Est.	2005 Est.	2006 Est.	2007 Est.	2008 Est.	2009 Est.	Breakdowns by % 1999-03	 2004-09
Network operation	**0**	-	-	-	-	-	**108**	23	19	22	19	25	**153**	25	25	25	26	26	26	14%	14%
Network maintenance - pole replacement	**0**	-	-	-	-	-	**5**	3	3	-	-	-	**0**	-	-	-	-	-	-	1%	0%
Network maintenance - reactive	**0**	-	-	-	-	-	**66**	7	8	13	22	16	**101**	16	17	17	17	17	17	9%	9%
Network maintenance - vegetation control	**0**	-	-	-	-	-	**53**	6	7	11	13	17	**105**	17	17	17	17	18	18	7%	9%
Network maintenance - other preventive	**0**	-	-	-	-	-	**96**	15	12	17	19	33	**229**	37	37	37	38	39	40	13%	21%
Other operating costs	**774**	134	154	157	162	166	**436**	76	94	82	91	92	**524**	99	84	84	85	85	86	57%	47%
Total	**774**	134	154	157	162	166	**765**	130	142	146	165	183	**1,111**	195	181	181	183	185	186	100%	100%
Average actual expenditure p.a. 1999-2003 ($m)	153																				
Actual, 1999-2003, as pct of projected	99%																				
Actual in 2003 as pct of actual in 1999	141%																				
Projected for 2004 as pct of projected for 2003	106%																				
Projected for 2009 as pct of projected for 2004	96%																				
Opex for Possibly Excluded Services																					
Asociated with customer-funded connections	**0**	-	-	-	-	-	**0**	-	-	-	-	-	**0**	-	-	-	-	-	-		
Associated with cust-specific ancillary services	**0**	-	-	-	-	-	**2**	-	-	-	-	2	**17**	3	3	3	3	3	3		
Meter maintenance	**0**	-	-	-	-	-	**0**	-	-	-	-	-	**0**	-	-	-	-	-	-		
Metering services	**0**	-	-	-	-	-	**28**	4	4	6	6	8	**50**	8	8	8	8	8	9		
Public lighting	**0**	-	-	-	-	-	**22**	5	5	3	4	5	**35**	6	5	6	6	6	6		
Total (See note a/)	**46**	9	9	9	9	9	**52**	9	9	9	10	15	**102**	16	16	17	17	17	18		
Average actual expenditure p.a. 1999-2003 ($m)	10																				
Actual in 2003 as pct of actual in 1999	165%																				
Projected for 2004 as pct of projected for 2003	107%																				
Projected for 2009 as pct of projected for 2004	108%																				
Other Opex																					
Projected Y2K	**0**	-	-	-	-	-	**5**	5	0	-	-	-	**0**	-	-	-	-	-	-		
Projected FRC	**0**	-	-	-	-	-	**6**	-	0	1	1	4	**26**	4	4	4	4	4	4		
Total Opex																					
Regulated services	**774**	134	154	157	162	166	**765**	130	142	146	165	183	**1,111**	195	181	181	183	185	186		
Posibly excluded services	**46**	9	9	9	9	9	**52**	9	9	9	10	15	**102**	16	16	17	17	17	18		
Other opex	**0**	0	0	0	0	0	**11**	5	1	1	1	4	**26**	4	4	4	4	4	4		
Total	**820**	144	164	167	171	175	**828**	144	151	156	175	202	**1,239**	215	202	202	205	207	208		
Average actual expenditure p.a. 1999-2003 ($m)	166																				
Actual in 2003 as pct of actual in 1999	141%																				
Projected for 2004 as pct of projected for 2003	107%																				
Projected for 2009 as pct of projected for 2004	97%																				

Figures are rounded. Line costs and transmission-related expenditures are excluded.

Source: DNSP's submissions to Meritec Limited with adjustments by Meritec Limited where agreed with the DNSPs or where noted. The final adjustments and approvals are Meritec's opinion.

Interptetation: this table in its original form was prepared by Meritec Limited for inclusion in its review of capex and opex, 2003, and is valid only in the form in which it appears in their report. Reference should be made to the main text of the rep

a/ FY 1999-2003 possibly excluded services projections are estimates deducted by IE from its projections for regulated services in the same years. There is no change in the total projection.

8.0 Assessment – Country Energy

8.1 General

General Information and Documentation

The following general information and documentation was obtained from CE and reviewed:

(a) Recent annual reports including those of the pre-merger entities;

(b) Organisation chart, employee numbers and contracted services;

(c) Statement of corporate intent;

(d) Asset management plan;

(e) Network development plan and network planning criteria and guidelines;

(f) Selected procurement and construction specifications;

(g) Recent network performance reports including those of the pre-merger entities;

(h) A sample of the network single-line diagrams and maps.

We were given a summary of assets in service at 30 June 2002 and their age profile. A summary of the latter is reproduced in Table 21.

We obtained and reviewed general statistics and system performance data as summarised in Section 3 of the report.

We received and reviewed sub-transmission network utilisation data for the Terranora and Stroud networks and we received and briefly reviewed information on zone substation utilisation for the years 2002 and 2009.

Demand Forecast

CE outlined its approach to demand forecasting and gave us a copy of the NIEIR forecast report prepared for them in February 2003. CE advised us that historic trends are used as a base for and a check on econometric data. The forecasting model used is the energy technology module of NIEIR's institute multipurpose model. The main variables are industry output, capital stocks, major projects, household numbers and population growth at national and state levels. The model adjusts for the probability of different ambient temperatures. The penetration of air conditioning loads having poor load factors was considered but could not be quantified. The model uses census district data aggregated to the level of local government areas, then former county councils, then the pre-merger distribution businesses, and then finally to CE as a whole.

We considered CE's medium-growth forecast to be the appropriate choice for the purpose of our review.

Demand-Side Management

CE advised us that approximately 1,500 MW of load was controlled by ripple control systems and time clocks. It reported that it had no specific interruptible load tariffs in use. It advised us that it has been working closely with SEDA for the last 12 months but with limited success to date in implementing demand management projects although it will continue to attempt to find alternatives to network augmentation where possible. It said that it is proposing the mandatory application of time-of-use pricing for all new customers from July 2004. It also advised us that it is establishing a dedicated Demand Management Group and has appointed a Demand Management Manager to work jointly with stakeholders to develop and implement demand management alternatives to network development such as the Binda Bigga project that is being invested jointly with SEDA.

CE gave us the following list of demand management programmes carried out over the past 12 months:

Table 1 - Demand Management Projects 2002/2003				
	Demand Management Program Investigations	**Demand Management Programs Implemented**	**PV of Costs of Demand Management Strategies**	**PV of Capital Expenditure Deferment plus Operating Expenditure Saving**
Individual large projects				
1	Bourke – DM study deferred following reduced load on the high voltage feeder following mine down scaling.	Investigations deferred to 2003/04	N/A	N/A
2	Mid North Coast of NSW - Request for Proposal jointly released with Transgrid	Nil	$2,520	$0
3	Western area of NSW - Request for Proposal jointly released with Transgrid	Nil	$2,520	$0
4	Forster and Tuncurry areas – investigate methods to reduce peak demand	Capacitor installation => Peak Load reduction	$146,000	$792,211
5	Lismore area – investigate methods to reduce peak load	Load shifting was achieved by replacing 5000 frequency injection relays	$550,000	$202,597
6	Finley – Investigate methods to reduce peak load	Load shifting by altering frequency injection program times	$3,000	$313,080
7	Crookwell Binda Bigga distribution feeder – Partnership with SEDA to investigate methods to reduce peak loads	Investigations expected to be completed in 2003/04	N/A	N/A
Sub-totals	6	3	$704,040	$1,307,888
Consolidated and Individual Smaller projects				
1	Successfully liase with 8 large commercial customers to install power factor correction equipment	Capacitor installation => Peak Load reduction	$144,711	$1,478,794
2	Installation of relay/time clocks in 9348 new network connections Country Energy wide	Load shifting	$560,880	$1,500,000
3	Yetta Dhimmakkal Correctional Centre – Investigate methods with customer to reduce demand via energy substitution, gas water heating, backup diesel generation, etc	Customer employed some gas water heating	$2,500	$0
Sub-totals	3	3	$708,091	$2,978,794
Totals	**9**	**6**	**$1,412,131**	**$4,286,682**

We concluded, however, that demand management prospects in CE's area are not likely to have a material impact on their capex requirements within the period FY 2004-2009 but have the propensity to make a meaningful impact in the future.

Distributed Generation and Other Non-Network Solutions

CE advised us that there are small hydropower stations at Oaky and Nymbodia within the service area. It considers that the most likely expansion of distributed generation in its service area will be in the form of wind generation with the majority of likely sites located in the Goulburn area. At least six proponents are expressing interest and it is considered likely by CE that it will see several implemented over the next five years. Of the current prospects, one is definitely considered likely to come on line but will have no impact on capex and the other will require network reinforcement. CE expect other projects to arise but do not have details at present.

We concluded that embedded generation prospects in CE's area within the period FY 2004-2009 are not material in terms of this review.

Independent Forecast

We were provided with data to prepare our own forecast of future demand should we consider that step necessary but on review of CE's own forecast, noting its comprehensiveness and its independent development by NIEIR, we concluded that (a) we could not improve on the accuracy of CE's own forecast with the data available to us; and (b) CE's forecast was in our opinion reasonable for the purpose of this review.

8.2 Actual v. Projected Capex for FY 1999-2003

Definition of Capex

We asked CE to confirm its definition of capex with reference to the NSW Treasury's *Guidelines for capitalisation of expenditure in the NSW public sector, June 2000.* CE's response suggested that its definition of capex is substantially or fully compliant with the Guidelines but it did note areas where judgement is used.[26]

Actual v. Projected Capex

CE was asked to enter its actual capex in the years FY1999-2003 under certain prescribed headings in the template together with its capex projections made at the time of the 1998 capex review.

As with the other DNSPs CE was also asked to explain the reasons for changes in expenditure under the headings listed below. Initially it was not able to enter its

[26] CE noted that for the purpose of the 2004 determination pole replacements have been capitalised but that they were expensed in the audited 2002 regulatory accounts.

projections because there was doubt about the figures that should be assumed for its pre-merger entities.[27] This issue was resolved but the responses reported in parenthesis in the following paragraphs relate to departures from the *approved* expenditures of CE's pre-merger entities, not from their projections:

(a) Changes in projected or actual load or in load patterns during the period (CE replied: growth related capital expenditure has generally been in accordance with the Worley estimates in 1999 and within the 10% materiality. The growth-related capex has been increasing along the northern and southern coastal strips at an ever-increasing rate over the current period due to the growth in new customer connections and energy demand primarily. This has occurred as a direct result of economic activity in that region, increased penetration of air-conditioners, which is increasing peak demands in summer, and the housing boom assisted by the new home buyers' incentives from the Federal Government. This has created a requirement for an increase in system reinforcement in these areas. This is expected to continue into the forthcoming regulatory period. For the network west of the ranges, growth has been relatively moderate during the current regulatory period and is expected to continue in the forthcoming regulation period. In some cases increases in demand in areas such as the northern and southern coastal areas have taken place without the need to significantly augment assets through higher utilisation and without contravening the planning guidelines. In some cases however, it was not possible to continue to connect new load without major augmentation in order to maintain sub-transmission network security and not compromise the network adequacy requirements);

(b) Changes in installed unit costs from those assumed in its 1998 projections (CE replied that its projections for asset replacement and renewal for the *forthcoming* regulatory period had been based on the unit rates as contained in the Guidelines);

(c) The need for compliance with new statutory obligations, if any, introduced during the period (CE replied: the Ministry … has introduced a new regulation "Electricity Supply (Safety and Network Management) Regulation 2002" that imposes a number of requirements relating to the maintenance of network assets and the prevention of bushfires. Programmes required to meet these new safety-focussed demands include the development and implementation of a network management plan and bush fire risk management plan. The regulations set out the basis for (future) maintenance requirements for CE. Compliance with the requirements of the regulation can only be achieved by increasing the annual operating and maintenance expenditure and the asset renewal requirements in the current period and moving forward. The Ministry has commented in a report "Regulatory Impact

[27] The situation was complicated by the fact that additional sums were allowed for its pre-merger entities in 1999.

Statement: Electricity Supply (Safety and Network Management) Regulation 2002, June 2002" that the regulation will have a financial impact on distributors and will lead to additional incurred costs);

(d) The advancement or deferral of expenditures during the period other than for reasons already listed (CE replied that there had been no material variation in this respect);

(e) Adoption of new policies, planning criteria or designs following its amalgamation if any with other DNSPs (CE replied that there had been no material variation in this respect);

(f) Planning or budgeting errors (CE replied that there may have been estimation errors for asset replacement and renewal and, more importantly, non-system capital expenditure as provided for in the 1999 determination of expenditure allowances. It noted that non-system expenditure had generally been omitted, that adequate planning information had not been available in all the pre-merger entities, and that planned renewal capex was very low as a percentage of network replacement cost in NorthPower's case);

(g) The extent to which Y2K or full retail contestability costs added to expenditure (CE replied: the distribution businesses faced significant costs associated with the introduction of FRC. The Tribunal has reviewed the prudence of these capital costs during the current regulatory period. The PB Associates FRC report recommended that costs of $21 million in capital expenditure be allowed for the period to June 2004, representing almost the full amount of efficient cost claim made by CE in our FRC expenditure submission to the Tribunal. This expenditure [had not been foreseen] for in the 1999 regulatory allowances for non-system expenditure);

(h) The extent to which changes in its policies for overhead cost allocation increased the cost of capital works (CE replied that there had been no material variation in this respect);

(i) The extent to which non-network solutions and demand-side management measures reduced capex (CE replied that there had been no material variation in this respect);

(j) Other factors, for example: the net cost after insurance recoveries of remedying damage (CE replied, in summary, that the comparison of actual expenditure during the current regulatory period with the regulatory allowances must take account of changes in scope and functions of the distribution business, events and circumstances beyond the control of distributors, changes in operating and other

> conditions, and the real costs of delivering distribution service to regional and rural NSW. The assumptions made by Worley in developing the capital expenditure program would require reassessment, with the passage of time since the report was prepared, particularly in relation to non-system investments. Adjustments would need to be made to account for the above factors. [CE] believe the additional costs incurred … to be both necessary and efficient. The principal reasons for the differences between the Tribunal's allowances and actual spends are …: (a) CE has made significant investments during the current regulatory period in upgrading and developing information technology and [related] systems [with an initial focus on] FRC systems; (b) for the former distributor NorthPower there was an adjustment to the projected expenditures for vehicles to take account of the vehicle trade-in values, the total net allowance included in the Worley review for Country Energy for motor vehicles was $2.6 million, as a result of changes to sales tax rulings the net capital cost to CE is expected to be of the order of $20 million in FY 2003 with an ongoing cost for vehicles and heavy plant of the order of $25 million p.a. over the forthcoming regulatory period).

We discussed these responses with CE. It was agreed that CE staff would reconstitute the projections of the pre-merger entities, combine them, and then incorporate in them the adjustments agreed with IPART in 1999. This was done and the results are incorporated in Table 6 in Section 4 of the report and in Table 22 in this section of the report. The main adjustments made were the inclusion of the additional capex projected and agreed for GSE in 1999 prior to the conclusion of the determination, the inclusion of the full budget originally requested for NorthPower's vehicles, and the increased budget for Advance Energy's replacement expenditures agreed with us (Worley) during 1998.

Based on these reconstituted projections, comparison of CE's actual expenditures with its own (reconstituted) projections shows an over-run of 31% over the period FY 1999-2003 as indicated in Table 6. Of this over-run, approximately 11 percentage points arose through additional capital contribution-funded work, 9 percentage points arose through additional non-system capex and 6 percentage points arose through additional growth-related capex. The balance of 5 percentage points was explained by other factors.

Our opinion is that, based on the information made available to us and on our own assessment, we had no reason to judge any material component of CE's actual capex during the period FY 1999-2003 imprudent.

Table 22 summarises CE's capex data.

8.3 Capex Projections for FY 2004-2014

Network Planning Criteria

We obtained from CE information on its documented network planning criteria for sub-transmission systems, high voltage distribution systems and low voltage distribution systems. We also asked for and obtained information on the length of planning period assumed in its long-term network planning process. We asked when the criteria had last been reviewed, whether the security of supply criteria were deterministic, probabilistic or both, and what plant rating criteria were applied. CE provided us with comprehensive information in response and advised us that their criteria had been reviewed comprehensively in June 2002 following the merger of the previous entities. We considered their criteria reasonable.

We asked for and obtained information on their plant ratings and considered them reasonable.

Optimality of Design and Construction Practices

We asked to what extent cable, conductor and equipment sizes, circuit designs and procurement were optimal. CE noted in reply that it had been formed from the amalgamation of 24 distributors and that it had established optimal designs for future work. It acknowledged that it had not finished the review of its procurement and construction specifications but had maximised potential savings by concentrating on the most frequently used items. It said that many of the results of its review of practices and materials had been incorporated into its standard practices already.

We noted these points but considered that the designs assumed were reasonable.

Unit Installation Costs and Standard Lives

We asked CE to indicate whether its unit installed costs and standard lives assumed when preparing capex projections were in accordance with Appendix C of the NSW Treasury's Guidelines (there is no requirement for them to be if the alternative approach used is sound). CE replied that they were. CE noted that the standard costs in the Guidelines were initially reviewed and updated in 2001 based on market rates provided by the contracting units of the DNSPs but that in carrying out the ODRC valuation in 2002 SKM had reviewed the standard costs for all assets and, where warranted, changes were made and the SKM rates integrated into the Guidelines. We thus accepted CE's cost estimates as reasonable for the purpose of this review.

Methodology for Determining Replacement Capex

We asked CE to outline its approach to determining replacement capex and noted that condition-and performance-based assessments were used with age used as a proxy when reliable information is not available. CE reported that the main drivers for replacement and renewal of zone substation equipment excluding transformers were obsolescence (the lack of spares), safety or increasing fault levels. CE advised us that replacement expenditure on power transformers is based on condition monitoring including dissolved gas analyses; the condition of pole-top structures is verified by inspection; and its pole and line inspection and maintenance procedures comply with the requirements of the Industry Standard *Guide to the inspection, assessment and preservation of wood poles EC8* published by the ESAA.

Impact of Statutory Obligations on Capex

We asked CE to estimate the impact on capex of statutory obligations including but not limited to safety, environmental protection and quality of supply. CE replied that impacts arose through asset renewals due to statutory (safety and environmental) reasons estimated to cost $5 million p.a. for the forthcoming period and through other causes similar to those identified by other DNSPs. We noted the impacts arising and considered the estimates reasonable for the purpose of this review.

Capex Evaluation and Approval Processes

We reviewed the capex evaluation and approval processes followed from project identification to approval and considered them appropriate for the purpose of this review (CE provided us with a comprehensive statement of its policies and practices in this area).

Capex Projections

We received CE's projections of capex for the period FY 2004-2014. We were given a detailed schedule of line items making up the projected expenditures and noted that the expenditures covered the full range of network and non-network expenses including the replacement of obsolete gear, installation of new equipment to improve voltage conditions on the network and to meet load growth, new customer connections, metering and load control equipment, the modification of mobile plant to comply with current requirements and other items.

We discussed the programme with CE's staff, receiving explanations in response to our questions particularly in relation to network constraints, and we reviewed the details of the major projects and programmes included in CE's Network Development Plan.

We noted that we were generally familiar with the situation and the condition of the network through prior work for IPART and some of the pre-merger entities.

We were satisfied, on the basis of the information made available to us, that the individual projects and programmes were justifiable for the purpose of this review and we were satisfied also that the overall magnitude of the programme was reasonable.

Our opinion is therefore that CE's capex projections may be accepted as reasonable without adjustment.

8.4 Actual v. Projected Opex for FY 1999-2003

Maintenance Practices

We received information on and reviewed CE's principal maintenance practices. We asked what percentage of work was carried out live and CE replied that about 14% of line work was.

Operational Logistics and Practices

We obtained information on CE's operational logistics (stores, procurement, fleet and plant management, staff numbers and deployment) and practices (including shut-down management processes and out-sourcing), specifically whether the practices had been reviewed and improved recently. Also, whether its operational policies had been reviewed and improved. CE gave a comprehensive reply that indicated acceptable practices as far as the purpose of this review is concerned. It noted that a wide-ranging review was carried out following the merger in FY 2002, two major reviews of fleet management had taken place since 2001, a review of operational policies was undertaken at the time of the merger, and its present challenge is to find more ways to make further efficiency improvements. It reported that it has commenced a business improvement programme aimed at establishing an overall plan to identify and realise any further sustainable business efficiency gains in non-field areas. The areas of focus include non-labour operating cost control, increasing efficiency through process improvement, identification of better practices and emerging trends, and possibly structural improvements. Resulting initiatives include a review of procurement & sourcing functions, a review of office supplies and services expenditure, and a review of inventory management. It out-sources asset inspection, vegetation control, zone substation maintenance, meter reading and supplementary maintenance support as required.

CE reported that it has adopted the use of electronic protection equipment, electronically controlled voltage regulators are now standard items, its SCADA system has been reviewed, and standard equipment and designs are being employed. Fault indicators have been used for some time by the pre-merger entities as a fault-finding mechanism.

CE noted that the benefits of merger efficiencies realised during the current regulatory period were reflected in its opex forecasts but that 'only technological innovation can lead to significant cost savings … and this is unlikely to occur in the forthcoming regulatory period'.

Asset Knowledge

We asked CE about the adequacy of its geographic information systems and other databases used for operation and maintenance purposes and for determining capex and renewal programmes. CE replied that it had three databases from the pre-merger entities, each integrated with a geographic information system, and that it had a project in hand to amalgamate them scheduled for roll-out this year 2003. It is satisfied that up-to-date data exists for operation of the sub-transmission and HV distribution networks and that most of the outstanding data capture work is associated with the low voltage networks and non-critical information.

Cost Efficiencies Arising from Integration

CE reported that it had faced significant challenges since formation with a number of issues including cultural and operational differences. A comprehensive integration project had been initiated and implemented, taking about a year to complete. Most integration actions have now been completed, it said, and benefits have included: reduced capital expenditure and maintenance costs, increased service levels, improved customer satisfaction and more effective and flexible utilisation of resources. CE said that these savings were reflected in CE's FY 2002 accounts.

Service Standards and Actions

We asked CE for details of its current service standards to judge their reasonableness and were satisfied that its performance measures were in reasonable alignment with industry standards where practicable. We did not consider that there were any features in the information presented that would impinge inappropriately and materially on capex or opex for the purpose of this review.

Comparison of Actual and Projected Opex for FY1999-2003

We asked CE to provide details of its projected opex during the period FY 1999-2003 for comparison with its own 1998 projections and to identify the reasons for any major departures from the projections under the following headings, giving reasons (its responses are given in parenthesis):

(a) Opex incurred in relation to Y2K and full retail contestability (CE replied: FRC costs incurred were submitted by CE and reviewed by PB Associates. IPART has allowed costs totalling $7.5 million covering the majority of the costs claimed. The 1999 expenditure forecasts did not anticipate these costs);

(b) Opex arising each year during the period as a direct result of the amalgamation of the DNSP with others (CE's response was unclear but it did say that its FY 2002 regulatory accounts are void of any merger costs. This has been confirmed by the NSW Audit Office and that there are no merger/amalgamation costs included in actual opex as advised to us);

(c) Opex resulting from the need to comply with new statutory obligations that came into effect during the period and describe the nature of the obligations (CE's reply referred to the Electricity Supply (Safety and Network Management) Regulation 2002 but did not quantify the impact);

(d) Opex resulting from non-network solutions and the extent to which it exceeded the projections (CE replied that there had been no material variation in this respect);

(e) The balance of the difference between projected and actual opex (CE replied that 'any assessment of [its] actual expenditure during the current regulatory period must take account of changes in scope of the distribution business, additional functions and compliance requirements, events and imposed costs beyond [its] control, changes in operating and other conditions, the real costs of delivering distribution service to rural and regional NSW, [and its] unique environment and operating conditions'. CE identified as reasons for the overrun the cost efficiency factor applied in the 1999 determination and changes in cost structure. CE said that the latter included: changes in responsibilities associated with the implementation of FRC, additional maintenance costs incurred in alleviating maintenance backlogs, bushfire prevention inspection programmes, increased call centre costs, provision for improved network performance standards, higher insurance premiums, rises in cost of contracted services, workplace health and safety related costs – [regulatory amendments presently being considered would add further to CE's opex but have not been included in its forecasts], - vegetation and environmental obligations, compliance with environmental requirements for the disposal of hazardous materials and chemicals, the introduction of GST, increased regulatory compliance costs, IT support functions excluding FRC, administration of construction contestability and development of published engineering standards, additional security measures, asbestos mitigation, accuracy testing of metering, product liability for quality and reliability of supply, and the impact of labour costs).

We discussed these responses with CE. We noted that the UMS study commissioned by CE in or around 2002 and reported in Part 2 of its Statement of Corporate Intent – Part 2 is titled *Strategic Plan* – commented as follows: "CE's asset management plan conforms with industry best practice; CE's historical capital and operating expenditure is well below that of most other comparable organisations; and there is a substantial maintenance backlog that will require significant expenditure to overcome high risk defects". UMS went on to recommend additional resources equivalent to 180 employees for the first year and various other strategies that CE said it is implementing. CE's submission to us said that it had budgeted in FY 2003 for an additional 50 permanent field employees and a one-off $300,000 allowance for zone substation maintenance catch-up.

Also of interest, CE advised us that labour rates had moved at a rate 'well in excess of CPI' noting that the Australian Bureau of Statistics' wage cost index for NSW showed a net movement of 15.23% over the period FY 1999-2002. It said however this was offset to an extent by a reduction in labour hours by task and therefore an improvement in efficiency but, it said, the increase in rates outstripped the efficiency gains. The net impact was not quantified.

We concluded that, based on the information made available to us and on our own assessment, we had no reason to judge any material component of CE's actual opex during the period FY 1999-2003 imprudent.

Table 23 summarises CE's opex data.

8.5 Opex Projections for FY 2004-2009

We received CE's projections of opex for the period FY 2004-2009 together with an explanation of the method used to compile them. CE argued that its actual opex for FY 2002, as audited in the regulatory account returns, should form the starting-point for its forecast of opex, less pole replacement expenditure which will be capitalised, plus changes in opex requirements over the period reflecting the initiation of a targeted maintenance catch-up programmes, plus increments arising from inflation, demand growth and additional obligations and functions, plus an adjustment for changes in the operating environment in which its activities are undertaken.

CE said that that the mounting level of maintenance backlog in the form of pole maintenance, vegetation management, line and substation maintenance and inspection and other distribution equipment maintenance and inspection was a significant issue. It requested that "due consideration be given to the inclusion of an increased level of maintenance expenditure in order to facilitate specific catch-up resourcing to reduce the level of backlog". It pointed to a decrease in reliability levels since FY 2000 in support of this request.

CE said that it had commissioned the UMS Group to undertake an independent review and assessment of the current maintenance backlog including a review and validation of the existence of the inspection and defect-related backlog, a review of CE's current asset maintenance strategies and practices to ensure they are efficient, a review of asset management IT systems and processes, and for determination of a prudent and efficient resource requirement to control the current defect-related backlog requirements including process and efficiency improvements. CE said that the review confirmed the need for an extensive maintenance programme to fix pole and other line defects, an increased programme of inspection and maintenance of substations and associated earth systems, an increase in vegetation clearance, replacement of street lighting equipment and fittings and maintenance of pole-mounted plant to avoid oil leakages and malfunctions. The work is estimated to increase opex costs by $5 million p.a. from and including FY 2005. We did not consider ourselves bound by UMS's recommendations but we were guided by them.

We discussed the projected expenditures in the templates with CE's staff, including the reasons for the movements in total opex from year to year, and concluded that the scheduled expenditures were reasonable for the purpose of this review. We were also satisfied that the overall magnitude of the programme was reasonable.

We concluded that in our opinion CE's opex projections for the period FY2004-2009 were reasonable for the purpose of this review, without adjustment. By that we mean that the programme constitutes, as best we are able to judge, an efficient programme for the purpose of this review.

Table 21: Network Fixed Asset Age Profiles (CE)

Asset category	Unit	Number of assets commissioned in the period																	
		Pre-1921	1921-1925	1926-1930	1931-1935	1936-1940	1941-1945	1946-1950	1951-1955	1956-1960	1961-1965	1966-1970	1971-1975	1976-1980	1981-1985	1986-1990	1991-1995	1996-2000	2001-2002
132 kV tower lines	km																		
132 kV pole lines	km	3	6	15	29	48	70	86	91	83	74	93	92	103	134	214	239	177	58
132 kV U/G cables	km	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
66 kV lines	km	15	28	65	128	215	309	382	405	368	328	411	411	456	595	953	1061	788	259
66 kV U/G cables	km	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1
33 kV lines	km	9	16	37	73	122	176	218	231	209	187	234	234	259	339	542	604	449	147
33 kV U/G cables	km	0	0	0	0	0	0	0	0	0	0	4	4	6	4	4	6	20	1
11/22 kV lines	km	243	456	1045	2049	3447	4969	6140	6503	5905	5262	6606	6595	7318	9558	15298	17041	12656	4153
11/22 kV U/G cables	km	0	0	0	0	0	0	0	0	0	80	95	130	150	180	260	400	507	200
SWER lines	km	50	94	215	422	710	1023	1264	1339	1216	1083	1360	1358	1507	1968	3150	3509	2606	855
LV lines	km	54	102	233	456	768	1107	1367	1448	1315	1172	1471	1469	1630	2129	3407	3795	2819	925
LV U/G cables	km	0	0	0	0	0	0	0	0	0	108	136	158	192	222	320	491	638	261
Distribution transformers	No	0	0	0	14	9	21	168	578	1114	2273	6302	11583	18923	20776	18461	17184	14563	5213
132 kV CBs	No	0	0	0	0	0	0	0	3	3	5	6	4	0	13	15	7	28	5
66 kV CBs	No	0	0	0	0	0	0	0	21	22	46	62	36	17	126	50	24	5	9
33 kV CBs	No	0	0	0	0	0	0	0	1	14	22	16	32	18	22	21	17	25	13
11/22 kV CBs	No	0	0	0	0	0	0	0	89	84	189	336	147	126	158	126	142	163	37
Other distribution switchgear (all voltages)	No	78	146	334	655	1102	1589	1963	2079	1888	1682	2112	2109	2340	3056	4891	5449	4046	1328
Service connections	No	1642	3085	7060	13852	23296	33583	41498	43955	39910	35565	44648	44577	49462	64602	103396	115182	85541	28069
Revenue meters & load control relays	No	0	0	0	0	0	0	0	34000	61000	83565	104909	104751	142000	243000	315000	330000	315000	97000

Table 22: Capex (CE)

Country Energy Capex		($1998 million)						($ nominal million) (note a/)						($2003 million)											
Fin yr ending 30 June ->	Notes	**Total**	1999	2000	2001	2002	2003	**Total**	1999	2000	2001	2002	2003	**Total**	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Basis ->		**98 Projn**	98 Projn	98 Projn	98 Projn	98 Projn	98 Projn	**Actual**	Actual	Actual	Actual	Actual	Est.	**Est.**	Est.	Est.	Est.	Est.	Est.	Est.	Est.	Est.	Est.	Est.	Est.
Replacement - end of life		**237**	39	50	53	49	46	**303**	49	50	43	78	83	**929**	81	82	83	83	84	85	85	86	86	87	87
Environ, safety, stat, other	b/	**-**	-	-	-	-	-	**-**	-	-	-	-	-	**0**	0	0	0	0	0	0	0	0	0	0	0
Non-network capex		**134**	30	29	24	28	23	**206**	40	42	28	34	63	**660**	53	65	63	61	62	62	61	60	59	57	56
Total renewal / replacement		**371**	69	78	77	78	69	**509**	89	92	71	111	146	**1,589**	134	146	146	144	147	147	146	146	145	144	144
Growth (demand related)		**213**	37	46	45	41	44	**258**	53	29	64	45	67	**712**	65	65	65	65	65	65	65	65	65	65	65
Reliab. and qual. improvement	b/	**84**	12	18	19	18	17	**-**	-	-	-	-	-	**-**	-	-	-	-	-	-	-	-	-	-	-
Sub-total		**668**	118	142	141	137	130	**767**	143	120	135	156	213	**2,300**	199	211	211	208	211	212	211	210	210	209	208
Possibly excluded services:																									
Capital contribution works	71%	**83**	18	15	16	17	17	**188**	34	44	32	41	37	**388**	39	38	37	37	36	35	34	34	33	32	32
Metering	23%	**27**	4	4	6	8	6	**19**	3	2	3	3	7	**137**	14	13	13	13	13	12	12	12	12	11	11
Public lighting	6%	**7**	1	2	1	1	1	**6**	1	1	1	1	1	**97**	10	10	9	9	9	9	9	8	8	8	8
Sub-total	100%	**117**	22	21	23	26	25	**213**	39	48	36	45	45	**621**	62	61	60	59	57	56	55	54	53	52	51
Other capex (Y2K and FRC)		**-**	-	-	-	-	-	**22**	-	-	2	20	-	**-**	-	-	-	-	-	-	-	-	-	-	-
Total		**784**	140	164	164	163	154	**1,002**	181	168	173	222	258	**2,922**	261	272	270	267	269	268	266	265	263	261	259
Actual as percentage of projected								128%	130%	103%	106%	136%	167%												
Actual as percentage of projected after deducting capital contrib. works and Other Capex								113%	120%	84%	94%	110%	161%												
Annual average expenditure projected for FY 2004-2014 (total of all capex)														**266**											

Figures have been rounded. Transmission-related expenditure is excluded.

Source: DNSP's submissions to Meritec Limited with adjustments by Meritec Limited where agreed with the DNSPs or where noted. The final adjustments and approvals are Meritec's opinion.

Interptetation: this table in its original form was prepared by Meritec Limited for inclusion in its review of capex and opex, 2003, and is valid only in the form in which it appears in their report. Reference should be made to the main text of the repooriginal form was prepared by Merit

a/ Impact of cost increases due to inflation, if any reported by the DNSP concerned, is discussed in the main text of the report. An automatic allowance for increases has NOT been included unless quantitative supporting evidence has been provided.

b/ Expenditures have been included under asset renewals or are not material if zero has been entered.

Table 23: Opex (CE)

Country Energy Opex		($ nominal million)					($ nominal million)						($2003 million)								
Fin yr ending 30 June ->	**Total**	1999	2000	2001	2002	2003	**Total**	1999	2000	2001	2002	2003	**Total**	2004	2005	2006	2007	2008	2009	Breakdowns by %	
Basis ->	**98 Projn**	98 Projn	98 Projn	98 Projn	98 Projn	98 Projn	**Actual**	Actual	Actual	Actual	Actual	Est.	**Est.**	Est.	Est.	Est.	Est.	Est.	Est.	1999-03	2004-09
Network operation	**0**	-	-	-	-	-	**137**	28	28	31	25	26	**162**	26	26	27	27	28	28	15%	13%
Network maintenance - pole replacement	**0**	-	-	-	-	-	**35**	7	7	8	13	-	**0**	-	-	-	-	-	-	4%	0%
Network maintenance - reactive	**0**	-	-	-	-	-	**345**	70	70	77	63	65	**430**	65	71	72	73	74	75	38%	35%
Network maintenance - vegetation control	**0**	-	-	-	-	-	**97**	20	20	22	18	18	**114**	18	19	19	19	19	20	11%	9%
Network maintenance - other preventive	**0**	-	-	-	-	-	**45**	9	9	10	8	9	**53**	9	9	9	9	9	9	5%	4%
Other operating costs	**880**	160	167	174	184	194	**249**	26	26	43	75	78	**485**	78	79	80	81	82	83	27%	39%
Total	**880**	160	167	174	184	194	**907**	160	160	190	203	196	**1,244**	197	204	207	210	212	215	100%	100%
Average actual expenditure p.a. 1999-2003 ($m)	181																				
Actual, 1999-2003, as pct of projected	103%																				
Actual in 2003 as pct of actual in 1999	123%																				
Projected for 2004 as pct of projected for 2003	100%																				
Projected for 2009 as pct of projected for 2004	109%																				
Opex for Possibly Excluded Services																					
Asociated with customer-funded connections	**0**	-	-	-	-	-	**0**	-	-	-	-	-	**0**	-	-	-	-	-	-		
Associated with cust-specific ancillary services	**0**	-	-	-	-	-	**13**	2	2	2	3	3	**18**	3	3	3	3	3	3		
Meter maintenance	**0**	-	-	-	-	-	**0**	-	-	-	-	-	**0**	-	-	-	-	-	-		
Metering services	**0**	-	-	-	-	-	**32**	6	7	4	7	7	**46**	7	8	8	8	8	8		
Public lighting	**0**	-	-	-	-	-	**20**	4	4	4	4	4	**27**	4	4	5	5	5	5		
Total	**0**	-	-	-	-	-	**65**	13	13	11	14	15	**91**	15	15	15	15	15	16		
Average actual expenditure p.a. 1999-2003 ($m)	13																				
Actual in 2003 as pct of actual in 1999	115%																				
Projected for 2004 as pct of projected for 2003	100%																				
Projected for 2009 as pct of projected for 2004	107%																				
Other Opex																					
Projected Y2K	**0**	-	-	-	-	-	**0**	-	-	-	-	-	**0**	-	-	-	-	-	-		
Projected FRC	**0**	-	-	-	-	-	**7**	-	-	2	1	5	**1**	1	-	-	-	-	-		
Total Opex																					
Regulated services	**880**	160	167	174	184	194	**907**	160	160	190	203	196	**1,244**	197	204	207	210	212	215		
Posibly excluded services	**0**	0	0	0	0	0	**65**	13	13	11	14	15	**91**	15	15	15	15	15	16		
Other opex	**0**	0	0	0	0	0	**7**	0	0	2	1	5	**1**	1	0	0	0	0	0		
Total	**880**	160	167	174	184	194	**980**	172	173	202	217	215	**1,336**	212	219	222	225	228	231		
Average actual expenditure p.a. 1999-2003 ($m)	196																				
Actual in 2003 as pct of actual in 1999	125%																				
Projected for 2004 as pct of projected for 2003	98%																				
Projected for 2009 as pct of projected for 2004	109%																				

Figures are rounded. Line costs and transmission-related expenditures are excluded.

Source: DNSP's submissions to Meritec Limited with adjustments by Meritec Limited where agreed with the DNSPs or where noted. The final adjustments and approvals are Meritec's opinion.

Interptetation: this table in its original form was prepared by Meritec Limited for inclusion in its review of capex and opex, 2003, and is valid only in the form in which it appears in their report. Reference should be made to the main text of the repooriginal form was prepared by Merit

9.0 Assessment – Australian Inland

9.1 General

General Information and Documentation

The following general information and documentation was obtained from AI and reviewed:

(a) Recent annual reports;

(b) Organisation chart, employee numbers and contracted services (we noted that no significant activities are routinely contracted out by AI);

(c) Corporate plan (including information on AI's recent restructuring);

(d) Asset management plan (we noted amongst other things: a change in focus in AI's maintenance philosophy from reactive to integrated asset management, the establishment of an Assets Division, and that implementation of new systems is scheduled to take place over an 18-month period that commenced in July 2002. We also noted that AI's network priorities include increased maintenance, the implementation of voltage control measures and the implementation of SCADA; and that capital projects included upgrading of the Broken Hill to Mt Gipps 66kV feeder);

(e) Long-term network development plan (we were given an interim version: the plan is intended to be developed fully over next 12 months);

(f) Selected procurement and construction specifications (AI currently uses mix of former Broken Hill City Council, Murray River Electricity and AI-developed standards. Investigations into a long-term arrangement to use another DNSP's standards are progressing, as it is recognised by AI that maintenance of a standards base is difficult for a company of its limited size and resources);

(g) Recent network performance reports;

(h) Network single-line diagrams and maps;

(i) Maps showing the location of offices, depots, stores, facilities customers and load densities (We noted that the overall customer density is currently 2.1 customers per km of total line length, the overall maximum load density is approximately 8.4 kW/km total line length, and that Broken Hill, the only significant town, has a customer density of approximately 67 customers per km of 22kV line and a load density of approximately 175kW/km of 22kV line excluding the 220kV supply to the Perilya Mine).

We were given a summary of assets in service at 30 June 2002 and their age profile. A summary of the latter is reproduced in Table 24.

We obtained and reviewed general statistics, system performance data and network utilisation data as summarised in Section 3 of the report, noting that AI's database was not capable of producing all the information we requested.[28]

Zone Substation Utilisation

We obtained information on zone substation utilisation noting that most AI zone substations are not presently metered and those that are require manual reading which has not been carried out regularly in the recent past. We were advised that new network metering and measurement points are to be installed in conjunction with the planned SCADA system installation over the next two years.

We noted that firm capacity is presently inadequate or is expected to be inadequate by the end of the planning period at only two substations, Dareton and Murgah, and that works had been identified to address these issues (an additional transformer in the former case and power factor correction by the sole customer in the latter case).

Demand Forecast

We reviewed AI's forecast of future energy demand noting, as in the case of all other DNSPs except EA, that only one scenario was included in our data entry template although high- and low-growth scenarios were provided separately.

We noted that the forecast had been prepared using a trend methodology and considered it adequate for network planning purposes in AI's current stage of development. We noted that overall growth is heavily dependent on the twenty largest energy users, most particularly the largest customer. During FY 2002 the largest customer accounted for 37% of total energy used and the next 19 customers accounted for a further 10%. We noted that the forecast had been prepared after consultation with some of the largest energy users.

We considered AI's forecast to be reasonable for the purpose of our review.

[28] AI is implementing a new works and asset scheduling and programming system that, when completed, will enhance its asset management capability.

Demand-Side Management

We were advised that various loads, mainly hot water heating and irrigation but also some space heating, are controlled by ripple control systems and time clocks and that AI reported no specific interruptible load tariffs in use. AI was not able to give us a reliable figure for the magnitude of controlled load.

AI reported that it had no demand management systems, projects or programmes actively in place at present and we noted in this context that there are no material network constraints reported in the main load centre, Broken Hill, that AI's light rural feeders do not lend themselves to embedded generation of significant size, and that there is currently limited scope for demand management in commercial buildings in its area as development in the area is mainly related to agricultural activity and not to urban commercial development.

AI did, however, acknowledge that it should do more in the future to explore and promote demand management measures with the object of achieving demand reductions in the long-term and, it noted that it is currently establishing a special unit for the purpose. Opportunities will be explored once key positions within the division are filled. It provided us with a copy of its demand management strategy document outlining the initiatives it plans to consider. These include the consideration of pricing signals, community education, optimisation of controlled loads, advice to customers on energy efficient appliances and buildings and on efficient energy sources, consideration of customer supply agreements that allow load shedding, and consideration of distributed generation.

Our opinion is that, based on the information made available to us and on our own assessment, demand management prospects in AI's area within the period FY 2004-2009 are not material in terms of this review.

Distributed Generation and Other Non-Network Solutions

AI advised us that there are a "few minimal sized PV cell grid-connected panels in customers' premises; …that there is [an] experimental White Cliffs Solar power Station which has a peak output of approximately 50kVA; …that there are other projects are as per [its] half- year financial report… [but that they] are not expected to have significant impact on overall capex." AI also advised that a wind farm in Broken Hill is in the early stages of investigation.

We concluded that embedded generation prospects in AI's area within the period FY 2004-2009 are not material in terms of this review.

Independent Demand Forecast

We were provided with limited data to prepare our own forecast of future demand should we consider that step necessary but, on review of AI's own forecast, although noting that it had not been prepared or verified independently (there was no requirement for it to have been), we concluded that (a) we could not improve on the accuracy of AI's own forecast with the data available to us; and (b) AI's forecast was in our opinion reasonable for the purpose of this review.

9.2 Actual v. Projected Capex for FY 1999-2003

Definition of Capex

We asked AI to confirm its definition of capex with reference to the NSW Treasury's *Guidelines for capitalisation of expenditure in the NSW public sector, June 2000* and were advised that its interpretation was generally in accordance with the Guidelines.

Actual v. Projected Capex

AI was asked to enter its actual capex in the years FY1999-2003 under certain prescribed headings in our template together with its capex projections made at the time of the 1998 capex review. AI reported that assumptions had been made to align its historical expenditure with the requested reporting categories and that some inaccuracies may have resulted. We did not consider them likely to be material.

AI was asked to explain the reasons for changes in expenditure under the headings listed below (its responses are given in parenthesis):

(a) Changes in projected or actual load or in load patterns during the period (it replied: load projections were not carried out with any scientific basis in the 1998 projection and assumed nil growth over the period. This proved to be pessimistic);

(b) Changes in installed unit costs from those assumed in its 1998 projections (it replied: AI did not use unit costs in the 1998 projections and still does not for the reasons set out in its AMP);

(c) The need for compliance with new statutory obligations, if any, introduced during the period (it replied: analysis not available at present);

(d) The advancement or deferral of expenditures during the period other than for reasons already listed (it replied: expenditures have continuously been both advanced and deferred through the planning period as priorities, both internal and external (customers), have changed. This a normal part of the operation of a smaller DNSP, i.e. where a single major customer funded project can be highly significant in terms of annual resource (both planning/design and implementation resource allocation);

(e) Adoption of new policies, planning criteria or designs following its amalgamation if any with other DNSPs (it replied: analysis not available at present);

(f) Planning or budgeting errors (it replied: ad hoc long-range planning has been carried out to date but the processes will be expanded as part of the implementation of new business plans once key positions have been filled);

(g) The extent to which Y2K or full retail contestability costs added to expenditure (it replied: analysis not available at present);

(h) The extent to which changes in its policies for overhead cost allocation increased the cost of capital works (it replied; analysis not available at present);

(i) The extent to which non-network solutions and demand-side management measures reduced capex (it replied; no significant non-network solutions have been implemented to date. Some demand management activities including power factor correction and load profile alteration through switching times of controlled load have been implemented and have reduced maximum demand in parts of the network. No analysis of the impact of these measures on capex has been undertaken);

(j) Other factors, for example: the net cost after insurance recoveries of remedying damage (it replied: analysis not available at present).

We discussed these responses with AI and obtained details of the expenditures made including reasons for material items. There were 200 or more line items involved ranging in cost up to $1 million. The expenditures covered the full range of network and non-network expenses including the replacement of obsolete gear, installation of new equipment to improve voltage conditions on the network and to meet load growth, new customer connections, metering and load control equipment, the modification of mobile plant to comply with current requirements and other items. Fleet expenditures were broken down into expenditures on heavy plant and other vehicles. We discussed the scheduled expenditures with AI's staff and concluded that the expenditures were reasonable for the purpose of this review.

Our opinion is that, based on the information made available to us and on our own assessment, notwithstanding the comments made above, we had no reason to judge any material component of AI's actual capex during the period FY 1999-2003 imprudent.

Table 25 summarises AI's capex data.

9.3 Capex Projections for FY 2004-2014

Network Planning Criteria

We obtained from AI information on its documented network planning criteria for sub-transmission systems, high voltage distribution systems and low voltage distribution systems. We also asked for and obtained information on the length of planning period assumed in its long-term network planning process. We asked when the criteria had last been reviewed, whether the security of supply criteria were deterministic, probabilistic or both, and what plant rating criteria were applied. AI advised us that its planning criteria had not been documented fully (an outline is included in its Long-Term Network Development Plan) and that it was planned to carry out a comprehensive review as part of developing the interim Plan into a comprehensive document over the next twelve months. AI said that its permissible cable loadings were determined using Australian standard as were line ratings although it noted that the latter were more commonly limited by voltage drop than load. It said that transformer and switchgear ratings were generally determined in accordance with manufacturers' recommendations. We considered the explanations reasonable given AI's current stage of development and the further initiatives planned.

Optimality of Design and Construction Practices

We asked to what extent cable, conductor and equipment sizes, circuit designs and procurement were optimal. AI replied that no complete rationalisation had taken place post-amalgamation and it was possible that optimisation was required. We noted these points considered that the designs assumed were reasonable.

Unit Installation Costs and Standard Lives

We asked AI to indicate whether the unit installed costs and standard lives assumed when preparing capex projections were in accordance with Appendix C of the NSW Treasury's Guidelines (there is no requirement for them to be if the alternative approach used is sound). AI replied it used its own estimates and we accepted them as reasonable for the purpose of this review.

Methodology for Determining Replacement Capex

We asked AI to outline its policies for determining replacement capex and noted that condition-based assessments were used as the basis. We considered the approach appropriate.

Impact of Statutory Obligations on Capex

We asked AI to estimate the impact on its capex of statutory obligations including but not limited to safety, environmental protection and quality of supply. AI replied that it did not have an analysis available. AI confirmed however that the main local government obligation affecting capex was the requirement to reticulate new urban subdivisions underground. We noted that it had identified expenditures arising from these reasons and considered the estimates reasonable for the purpose of this review.

Capex Evaluation and Approval Processes

We reviewed the capex evaluation and approval processes followed from project identification to approval and considered them appropriate for the purpose of this review noting that AI had identified the need for improvement in its methods of analysis as part of the planned overhaul of its LTNDP and had also identified the need for business cases to be made for all capex programmes.

Capex Projections

We received AI's projections of capex for the period FY 2004-2014. We were given a detailed schedule of line items making up the projected expenditures and noted that, as in the cast of past capex, the expenditures covered the full range of network and non-network expenses including the replacement of obsolete gear, installation of new equipment to improve voltage conditions on the network and to meet load growth, new customer connections, metering and load control equipment, the modification of mobile plant to comply with current requirements and other items. The largest category was customer-funded connections. Other major categories were distribution mains improvements and system control. We discussed the programme with AI's staff and considered the scheduled expenditures were reasonable for the purpose of this review.

We noted that AI's business plan lists as an action point the preparation of detailed business cases to support the proposed capex and the presentation of these to its Board for approval. We anticipate that the majority of its capex items are therefore tentative to some degree and will be the subject to further assessment and review by the DNSP. Notwithstanding this, we were satisfied that the overall magnitude of the programme is reasonable.

We were satisfied, on the basis of the information made available to us, that the individual projects and programmes were justifiable for the purpose of this review and we were satisfied also that the overall magnitude of the programme was reasonable.

Our opinion is therefore that AI's capex projections may be accepted as reasonable without adjustment.[29]

9.4 Actual v. Projected Opex for FY 1999-2003

Maintenance Practices

We received information on and reviewed AI's principal maintenance practices. We asked what percentage of work was carried out live and AI replied that it was only a small proportion of possible HV work but that most LV line maintenance is carried out live. It said it was not expected that more than about 25% of HV work will be economical live. We accepted the analysis as reasonable for the purpose of this review.

Operational Logistics and Practices

We obtained information on AI's operational logistics (stores, procurement, fleet and plant management, staff numbers and deployment) and practices (including shut-down management processes), specifically whether its practices had been reviewed and improved recently. Also, whether its operational policies had been reviewed and improved. AI replied that no comprehensive reviews have taken place recently but that it was a requirement that all General Managers will undertake such reviews to meet its objectives in the current AI Business Plan.

We asked about AI's policies for out-sourcing and AI replied that although almost all of O&M activity has been carried out in-house to date the separation of Assets and Services into separate business units had commenced and might lead to a change in this policy.

Asset Knowledge

We asked AI about the adequacy of its geographic information systems and other databases used for operation and maintenance purposes and for determining capex and renewal programmes. AI replied that it had already recognised the need for improved systems and it explained to us the developments that are proposed or are being implemented to generate reliability statistics in the form now required, improve the

[29] Our approved figures do not include allowance for costs associated with the replacement of the existing gas turbine units with diesel power plant for back-up in the event of a 220 kV outage.

sharing of information, and to replace obsolete IT systems. Installation of a comprehensive SCADA system is scheduled to commence next year.

Cost Efficiencies Arising from Integration

AI said it had not been able to report cost efficiencies from its integration because: neither Broken Hill Electricity nor Far West Energy had its own head office and Murray River Energy's office in Albury had gone to Great Southern Energy in the split; neither of the two main organisations had their own computer system; no depot amalgamation was possible as major depots were at least 275km apart; there had been significant expansion through the Far West Electrification Scheme with an attendant growth in service area and line length in addition to taking over supply to the townships of Wilcannia, White Cliffs and Tibooburra within the last decade; cost efficiencies that could be quantified were directed towards manpower reductions with voluntary redundancies as a result of the amalgamations leading to savings although some of the positions (mainly, front-line services staff) made redundant at the time have since had to be re-established. We considered the explanations reasonable for the purpose of this review.

Service Standards and Actions

We asked AI for details of its current service standards and were satisfied that the performance measures cited were in reasonable alignment with industry standards where practicable. We did not consider that there were any features in the information presented that would impinge inappropriately and materially on capex or opex for the purpose of this review.

Comparison of Actual and Projected Opex for FY1999-2003

We asked AI to provide details of its projected opex during the period FY 1999-2003 for comparison with its own 1998 projections and to identify the reasons for any major departures from the projections under the following headings, giving reasons (its responses are given in parenthesis):

(a) Opex incurred in relation to Y2K and full retail contestability (it replied: analysis not available at present);

(b) Opex arising each year during the period as a direct result of the amalgamation of the DNSP with others (it replied: analysis not available at present);

(c) Opex resulting from the need to comply with new statutory obligations that came into effect during the period and describe the nature of the obligations (it replied:

analysis not available at present, however some of the items that increased opex over the period include: increased planning and training costs as a result of the need to produce and implement network safety and operating plans and procedures – significant costs; increased audit costs (internal and external) relating to the above; increased costs in collecting and reporting indicator data such as reliability, quality, responsiveness etc with costs of data collection and reporting on service standards far outweighing the minimal related compensation payments; increased maintenance costs due to employee and public safety issues such as asbestos in switchboards (both morally and economically prudent in the long term, but increased short term costs none the less); increased plant maintenance costs as a result of OH&S Regulation 2001 requirements; increased traffic control costs at work sites due increase in requirements in AS and RTA standards (called up in 2001 OH&S Regulations); increased cost of OHS&W consultation as a result of 2001 OH&S Regulations; increased cost of wood pole termite treatment as a result of hazardous chemicals legislation; increased cost of apprentice training as a result of new national qualification requirements, and withdrawal of distance learning options; FRC);

(d) Opex resulting from non-network solutions and the extent to which it exceeded the projections (it replied: analysis not available at present but not expected to be significant);

(e) The balance of the difference between projected and actual opex (it replied: analysis not available at present but expected to result mainly from inadequate planning processes when the projections were made).

We discussed these responses with AI and obtained details of the expenditures made or planned during the years FY 2003 and FY 2004. The detailed schedules identified items by cost category (66 kV rural, 22 kV urban, 22 kV rural, SWER, LV urban, LV rural, customer service, public lighting, substations, depot, pole inspection, tree lopping, fault repairs, line patrols and fire mitigation, condemned pole replacement, inspections, voltage complaints, disconnections and reconnections, etc) and indicated labour hours and overhead allocations. It was not possible within the time available to examine the schedule in detail. Nor was it necessary in our view to do so to form a view on the reasonableness or otherwise of the costs put forward. We discussed the scheduled expenditures with AI's staff and concluded that the expenditures were reasonable for the purpose of this review.

Our opinion is that, based on the information made available to us and on our own assessment, we had no reason to judge any material component of AI's actual opex during the period FY 1999-2003 imprudent.

Table 26 summarises IE's opex data.

9.5 Opex Projections for FY 2004-2009

We received AI's projections of opex for the period FY 2004-2009. We were given a detailed schedule of line items making up the projected expenditures that explained how the projected expenditures had been derived from the FY 2004 line items. We discussed the programme with AI's staff and considered the scheduled expenditures were reasonable for the purpose of this review.

The constituent programmes will be the subject of review in the normal course of the DNSP's business and variation from the projections can be expected, especially in later years. We also noted that preliminary investigations had been carried out to see what savings might be achieved by contracting out such items as pole inspections, meter reading and vegetation control. AI's projections incorporate the identified savings although the new arrangements are yet to be established. Overall, we were satisfied that the magnitude of the programme is reasonable.

We concluded that in our opinion AI's opex projections for the period FY2004-2009 were reasonable for the purpose of this review, without adjustment. By that we mean that the programme constitutes, as best we are able to judge, an efficient programme for the purpose of this review.

Table 24: Network Fixed Asset Age Profiles (AI)

Asset category	Unit	Number of assets commissioned in the period										
		Pre-1921	1956-1960	1961-1965	1966-1970	1971-1975	1976-1980	1981-1985	1986-1990	1991-1995	1996-2000	2001-2002
132 kV tower lines	km											0.00
132 kV pole lines	km											0.00
132 kV U/G cables	km											
66 kV lines	km		12.7	108.9				9.4	161.491	14.6	3.10	1.24
66 kV U/G cables	km											
33 kV lines	km								143	468.05		
33 kV U/G cables	km											
11/22 kV lines	km			62.5	149	82	272	106	390	462	375.12	150.05
11/22 kV U/G cables	km							1.62	1.24	2.83	2.10	0.84
SWER lines	km					499	317.5	680.3	249.4	3759.36	180.25	72.10
LV lines	km			172	56	21	86	14	17	17	124.85	47.46
LV U/G cables	km				0.37	2.4	5.6	2.5	2.38	2.05	8.28	3.31
Distribution transformers	No				350	350	350	350	350	359	859	43.71
132 kV CBs	No											47.46
66 kV CBs	No			1					3			
33 kV CBs	No									5		
11/22 kV CBs	No			5	3	4	3	3	12	6	93	7.00
Other distribution switchgear (all voltages)	No			15	28	30	30	30	30	30	458	42.00
Service connections	No	*										
Revenue meters & load control relays	No	*										

* Records not readily available.

Table 25: Capex (AI)

Australian Inland Capex		($1998 million)						($ nominal million) (note a/)						($2003 million)											
Fin yr ending 30 June ->	Notes	**Total**	1999	2000	2001	2002	2003	**Total**	1999	2000	2001	2002	2003	**Total**	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Basis ->		**98 Projn**	98 Projn	98 Projn	98 Projn	98 Projn	98 Projn	**Actual**	Actual	Actual	Actual	Actual	Est.	**Est.**	Est.	Est.	Est.	Est.	Est.	Est.	Est.	Est.	Est.	Est.	Est.
Replacement - end of life		**0.6**	0.2	0.2	0.0	0.0	0.0	**0.6**	0.1	0.1	0.2	0.2	-	**-**	-	-	-	-	-	-	-	-	-	-	-
Environ, safety, stat, other		**-**	-	-	-	-	-	**6.0**	2.1	0.4	0.7	1.4	1.4	**5.2**	1.0	0.6	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Non-network capex		**-**	-	-	-	-	-	**3.4**	0.4	0.6	0.7	0.7	1.0	**7.8**	1.4	0.9	0.9	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Total renewal / replacement		**0.6**	0.2	0.2	0.0	0.0	0.0	**9.9**	2.6	1.1	1.6	2.2	2.4	**13.0**	2.4	1.5	1.4	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Growth (demand related)		**5.4**	1.1	1.7	2.2	0.2	0.2	**3.1**	0.2	0.7	0.7	0.9	0.7	**7.3**	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Reliab. and qual. improvement		**1.6**	1.0	0.5	0.1	0.1	0.1	**2.6**	0.4	0.4	0.7	0.6	0.5	**9.4**	1.9	1.2	0.8	0.9	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Sub-total		**7.6**	2.3	2.4	2.3	0.3	0.3	**15.6**	3.1	2.2	2.9	3.7	3.6	**29.6**	4.9	3.3	2.8	2.5	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Possibly excluded services:																									
Capital contribution works	90%	**7.0**	1.4	1.4	1.4	1.4	1.4	**4.6**	1.2	0.9	0.6	0.9	1.0	**14.8**	1.6	2.1	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Metering	4%	**0.3**	0.1	0.1	0.1	0.1	0.1	**0.3**	0.1	0.1	0.1	0.1	-	**-**	-	-	-	-	-	-	-	-	-	-	-
Public lighting	6%	**0.5**	0.4	0.0	0.0	0.0	0.0	**0.2**	0.0	0.0	0.0	0.0	-	**-**	-	-	-	-	-	-	-	-	-	-	-
Sub-total	100%	**7.8**	1.9	1.5	1.5	1.5	1.5	**5.1**	1.3	1.1	0.7	1.0	1.0	**14.8**	1.6	2.1	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Other capex (Y2K and FRC)		**-**	-	-	-	-	-	**0.5**	0.0	0.0	0.1	0.4	-	**-**	-	-	-	-	-	-	-	-	-	-	-
Total		**15.4**	4.1	3.9	3.8	1.8	1.8	**21.2**	4.5	3.3	3.7	5.1	4.6	**44.5**	6.5	5.4	4.1	3.7	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Actual as percentage of projected								137%	108%	84%	99%	284%	258%												
Actual as percentage of projected after deducting capital contrib. works and Other Capex								191%	117%	94%	129%	989%	929%												
Annual average expenditure projected for FY 2004-2014 (total of all capex)														**4.0**											

Figures have been rounded. Transmission-related expenditure is excluded.
Source: DNSP's submissions to Meritec Limited with adjustments by Meritec Limited where agreed with the DNSPs or where noted. The final adjustments and approvals are Meritec's opinion.
Interptetation: this table in its original form was prepared by Meritec Limited for inclusion in its review of capex and opex, 2003, and is valid only in the form in which it appears in their report. Reference should be made to the main text of the rep
a/ Impact of cost increases due to inflation, if any reported by the DNSP concerned, is discussed in the main text of the report. An automatic allowance for increases has NOT been included unless quantitative supporting evidence has been provided.

Table 26: Opex (AI)

Australian Inland Opex		($ nominal million)					($ nominal million)						($ 2003 million)								
Fin yr ending 30 June ->	**Total**	1999	2000	2001	2002	2003	**Total**	1999	2000	2001	2002	2003	**Total**	2004	2005	2006	2007	2008	2009	Breakdowns by %	
Basis ->	**98 Projn**	98 Projn	98 Projn	98 Projn	98 Projn	98 Projn	**Actual**	Actual	Actual	Actual	Actual	Est.	**Est.**	Est.	Est.	Est.	Est.	Est.	Est.	1999-03	2004-09
Network operation	**0.0**	0.0	0.0	0.0	0.0	0.0	**1.0**	0.1	0.1	0.2	0.2 0.3		**2.8**	0.5	0.5	0.5	0.5	0.5	0.5	3%	5%
Network maintenance - pole replacement	**0.0**	0.0	0.0	0.0	0.0	0.0	**4.3**	0.6	1.0	0.8	1.1 0.9		**5.0**	0.9	0.9	0.8	0.8	0.8	0.8	12%	9%
Network maintenance - reactive	**0.0**	0.0	0.0	0.0	0.0	0.0	**5.0**	1.0	1.0	1.5	1.2 0.3		**1.3**	0.2	0.2	0.2	0.2	0.2	0.2	14%	2%
Network maintenance - vegetation control	**0.0**	0.0	0.0	0.0	0.0	0.0	**1.3**	0.2	0.3	0.3	0.3 0.2		**1.4**	0.3	0.3	0.2	0.2	0.2	0.2	4%	3%
Network maintenance - other preventive	**0.0**	0.0	0.0	0.0	0.0	0.0	**7.7**	1.3	1.3	1.8	1.8 1.5		**14.7**	2.6	2.5	2.5	2.4	2.4	2.3	21%	27%
Other operating costs	**37.1**	6.7	7.0	7.5	7.8	8.2	**16.9**	2.5	2.8	2.5	3.8 5.3		**28.9**	5.1	4.8	4.8	4.8	4.8	4.8	47%	53%
Total	**37.1**	6.7	7.0	7.5	7.8	8.2	**36.2**	5.7	6.5	7.1	8.4 8.4		**54.3**	9.5	9.1	9.0	9.0	8.9	8.8	100%	100%
Average actual expenditure p.a. 1999-2003 ($m)	7.2																				
Actual, 1999-2003, as pct of projected	98%																				
Actual in 2003 as pct of actual in 1999	147%																				
Projected for 2004 as pct of projected for 2003	112%																				
Projected for 2009 as pct of projected for 2004	93%																				
Opex for Possibly Excluded Services																					
Asociated with customer-funded connections	**0.0**	0.0	0.0	0.0	0.0	0.0	**0.1**	0.0	0.0	0.0	0.0 0.0		**0.1**	0.0	0.0	0.0	0.0	0.0	0.0		
Associated with cust-specific ancillary services	**0.0**	0.0	0.0	0.0	0.0	0.0	**0.2**	0.0	0.0	0.0	0.0 0.2		**1.3**	0.2	0.2	0.2	0.2	0.2	0.2		
Meter maintenance	**0.0**	0.0	0.0	0.0	0.0	0.0	**0.4**	0.1	0.1	0.1	0.1 0.1		**0.7**	0.1	0.1	0.1	0.1	0.1	0.1		
Metering services	**0.0**	0.0	0.0	0.0	0.0	0.0	**2.5**	0.5	0.5	0.6	0.7 0.3		**1.3**	0.3	0.2	0.2	0.2	0.2	0.2		
Public lighting	**0.0**	0.0	0.0	0.0	0.0	0.0	**1.1**	0.1	0.2	0.2	0.2 0.4		**1.3**	0.2	0.2	0.2	0.2	0.2	0.2		
Total	**0.0**	0.0	0.0	0.0	0.0	0.0	**4.3**	0.7	0.7	0.9	1.0 1.0		**4.7**	0.9	0.8	0.8	0.8	0.7	0.7		
Average actual expenditure p.a. 1999-2003 ($m)	0.9																				
Actual in 2003 as pct of actual in 1999	131%																				
Projected for 2004 as pct of projected for 2003	90%																				
Projected for 2009 as pct of projected for 2004	85%																				
Other Opex																					
Projected Y2K	**0.0**	0.0	0.0	0.0	0.0	0.0	**0.0**	0.0	0.0	0.0	0.0 0.0		**0.0**	0.0	0.0	0.0	0.0	0.0	0.0		
Projected FRC	**0.0**	0.0	0.0	0.0	0.0	0.0	**0.4**	0.0	0.0	0.1	0.3 0.0		**0.0**	0.0	0.0	0.0	0.0	0.0	0.0		
Total Opex																					
Regulated services	**37.1**	6.7	7.0	7.5	7.8	8.2	**36.2**	5.7	6.5	7.1	8.4	8.4	**54.3**	9.5	9.1	9.0	9.0	8.9	8.8		
Posibly excluded services	**0.0**	0.0	0.0	0.0	0.0	0.0	**4.3**	0.7	0.7	0.9	1.0	1.0	**4.7**	0.9	0.8	0.8	0.8	0.7	0.7		
Other opex	**0.0**	0.0	0.0	0.0	0.0	0.0	**0.4**	0.0	0.0	0.1	0.3	0.0	**0.0**	0.0	0.0	0.0	0.0	0.0	0.0		
Total	**37.1**	6.7	7.0	7.5	7.8	8.2	**40.9**	6.5	7.2	8.0	9.8	9.4	**59.0**	10.4	9.9	9.8	9.7	9.6	9.5		
Average actual expenditure p.a. 1999-2003 ($m)	8.2																				
Actual in 2003 as pct of actual in 1999	146%																				
Projected for 2004 as pct of projected for 2003	110%																				
Projected for 2009 as pct of projected for 2004	92%																				

Figures are rounded. Line costs and transmission-related expenditures are excluded.

Source: DNSP's submissions to Meritec Limited with adjustments by Meritec Limited where agreed with the DNSPs or where noted. The final adjustments and approvals are Meritec's opinion.

Interptetation: this table in its original form was prepared by Meritec Limited for inclusion in its review of capex and opex, 2003, and is valid only in the form in which it appears in their report. Reference should be made to the main text of the rep

10.0 Key Issues for the Tribunal

In concluding this report we would like to note the following key issues for the Tribunal's consideration.

10.1 Prudence Test of Past Capex

A concern expressed in our interim Draft Report was that, whilst the DNSPs may have set out to manage their programmes in accordance with the capex assumed necessary by the Tribunal, there were significant variations from the projected programmes. Our question at the time was whether this implied a lack of financial discipline or rigour in the sector. We would have expressed the point more accurately if we had used words similar to those chosen by Halcrow in its overview report to IPART of December 2002 on the NSW water agencies. The report noted in this context, correctly in our view, that a test of prudence is softer than a test of efficiency and may reduce the incentive for the regulated agencies to develop robust asset management procedures and deliver capital efficiencies. If all capex that passes a test of prudence is rolled forward automatically into the regulated asset base, the penalty for overspending, including failing to deliver expected capital efficiencies, is largely the cash flow difference in the price path. The shorter the path, the less the incentive. Where over-expenditure is for reasons that should have been foreseeable, the penalty is the same.

The benefits of exceeding expectations on capital efficiency are similarly short-term and give little incentive to out-perform the determination.

Whilst the difficulty of adapting determinations to changing circumstances remains, we would suggest that the Tribunal give further consideration to this issue.

10.2 Opex Base

A second point made in the Halcrow report was that the base for opex should not be re-set at every price determination to reflect actual costs. They noted that agencies are sometimes faced with unexpected costs outside their control and that the Tribunal might take a sympathetic view about such expenditures. However, they also noted that where additional expenditure is reasonably foreseeable, a different approach may be appropriate.

Our terms of reference clearly took this point into account as we were asked to examine prior opex with the purpose of assessing a reasonable starting level for future opex. We did, however, face an instance of this type in being asked by EA to agree to significant increases in its opex over the period, increases that would have had the effect, if agreed to, of re-positioning its opex base. At least, that was our opinion. Our view in that case was that existing and desirable economies should not be done way with. Implicitly we supported Halcrow's point and suggest that it be taken into account by the Tribunal when weighing up our recommendation on the matter.

10.3 Future Opex and Capex

Experience shows that infrastructure assets of this type should not be allowed to run down over time. On the other hand our view is that asset lives should be extended for as long as is economic and, where possible, new methods should be found to defer replacement expenditures. A trade-off is needed between replacement capex and opex and we noted that studies are being undertaken in this area by several if not all DNSPs. We noted also that modern equipment is generally designed to be as free of maintenance as possible in recognition of the high cost of labour in developed countries. Further work would be desirable on a study of economic asset lives in the sector in this context.

Appendices

Appendix A: List of Officials Met or With Whom Discussions Held

Meetings or discussions were held with the following officials in addition to those attending the public forum held on 11 July 2003:

Energy Australia
George Maltabarow
Trevor Armstrong
Doug Ackland
Rob Baxter
Peter Birk
Matt Cooper
Terry Fagan
Neil Gordon
Michael Martinson
Nives Matosin
Michael Pennings
Robert Smith

Integral Energy
Richard Powis
Karen Waldman
Matt Webb
Ty Christopher
Alan Flett
Rod Howard
Craig James
Peter Langdon
Frank Nevill
David Neville
Brian O'Connell
Joe Pizzinga
Michael Tamp
John Wallace

Country Energy
Lawrence Zulli
Terry Holmes

Australian Inland
Linda Heane
Peter Jamieson

Adrian Ray
Ray Thorn

Ministry of Energy and Utilities
Paul Grant

Sustainable Energy Development Authority
Chris Dunstan

Representing the Energy Users' Association of Australia
John Dick
Bob Lim
Jeff Washusen

Appendix B - Questionnaire for Completion by the DNSPs

FOR COMPLETION BY DNSPs

INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

QUESTIONNAIRE

FOR TOTAL COST REVIEW OF DNSPs

____

(Enter Name of DNSP here)

FEBRUARY 2003

1031 694 01 Rev. 3F

LIST OF CONTENTS

1. INSTRUCTIONS FOR COMPLETION OF QUESTIONNAIRE AND ACCOMPANYING TEMPLATE

1.1 Background and Intent

This questionnaire and the accompanying template (spreadsheet) has been compiled by Meritec Limited (Meritec) and is issued to gather supplementary information for the *Total cost review of DNSPs* being carried out for the Independent Pricing and Regulatory Tribunal of NSW (IPART) in preparation for IPART's forthcoming determination of DNSP network charges. The information provided and representations made in your completed questionnaire will be relied on by Meritec in advising IPART and will be made available in full to IPART. Meritec may make adjustments to your projections when advising IPART. If so, you and IPART will be informed. It is envisaged that Meritec's draft report to IPART will be provided to you for comment prior to the submission of our final report and recommendations.

1.2 Interpretations and Response

Please make every endeavour to use the definitions and structure requested to assist the work.

Unless stated, all entries should correspond to your 'medium growth' scenario with existing service levels as defined in the *Information Request.*

Your response should be fully consistent with your response to the Secretariat's *Information Request* issued in November 2002. As far as possible, duplication of requests for data in the two documents has been avoided other than for clarity or the convenience of the parties in completing or analysing the data.

Where requested, please enter your responses directly into the questionnaire using *Word* or into the template using *Excel*. Where providing documents in electronic form, please use *.doc* or *.pdf* files for documents, *.xls* (preferably) or *.doc* for data, *.dgn* or *.dwg* for drawings, and *.e00* or *.shp* for GIS data. Supplementary pages may be added at the end of the questionnaire if appropriate but please make reference to them in the spaces provided in the main text.

Once completed, the questionnaire and template are to be submitted electronically. Other data should preferably be sent electronically as well but may be in printed form if more practical.

Please submit all electronic material **on a CD**, not by email. One copy will be sufficient.

1.3 Queries

Please address any queries by email to:

Jeffrey Wilson	*with a copy to*	Michael Whaley
jeffrey.wilson@meritec.org		michael.whaley@meritec.org
Phone +64 9 379 1225		Phone +64 9 379 1291
Fax 379 1230		Fax 379 1230

Our responses to queries will be circulated to all DNSPs by email with a summary of the query.

1.4 Dates for Submission

The completed questionnaire and template are to be submitted to Meritec with the accompanying detailed supporting documentation on or before **Thursday 10 April 2003**. However, it is requested that the general information and documentation requested in Section 2 be submitted to Meritec on **Friday 28 March 2003**.

1.5 Address for Submission

The address for submission is:

Meritec Limited
47 George Street Newmarket
P.O. Box 4241 Auckland
NEW ZEALAND

Attn: Mr J W Wilson

1.6 Further Information May Be Requested

Further information may be requested from you after receipt of your response.

1.7 Confidentiality

The material provided by you will be kept confidential to Meritec and IPART except as required for the preparation of Meritec's report to IPART and IPART's subsequent actions. Note in this context that IPART intends to make public both Meritec's draft report and final report. Meritec will use your information only for the purpose of the study.

1.8 Intellectual Property

The questionnaire and template are the intellectual property of Meritec and IPART and are not to be used by other parties or for any purpose other than your response.

1.9 Definitions

Unless indicated otherwise in the text, the following definitions shall be applied:

General Definitions

- ***Averages:*** Averages are arithmetic averages unless a weighted average is asked for.
- ***Expenditure:*** In the context of this questionnaire, expenditure means the value of resources consumed in a period or applied to a capital work during its completion determined on an accrual accounting basis.
- ***Capital expenditure:*** See Section 7.1 for the definition of capital expenditure (capex) and note the further definitions in the User Guide accompanying the *Information Request.*
- ***Lengths:*** The definition of system length is that in the *Utility regulators' forum discussion paper, March 2002* that is (in précis): the route length of lines in service including overhead lines and cables, excluding low voltage service connections, treating double-circuit lines as two lines.
- ***Transmission Assets (EnergyAustralia only):*** *see the questionnaire.*

Definitions Relating to Reliability of Supply

- ***Interruption:*** cessation of supply of electricity to a customer for more than one minute.

- ***Performance Ratios:***

SAIDI = Sum of [Number of Interrupted Customers X Interruption Duration] (minutes/connected customer/year)
Total Number of Connected Customers

SAIFI = Sum of [Number of Interrupted Customers] (interruptions/connected customer/year)
Total Number of Connected Customers

CAIDI = Sum of [Number of Interrupted Customers X Interruption Duration] (minutes/customer interrupted)
Sum of [Number of Interrupted Customers]

- ***Adverse Environment:*** customer interruptions due to equipment being subject to an abnormal environment such as salt spray, industrial contamination, humidity, corrosion, vibration or fire.
- ***Adverse Weather:*** customer interruptions resulting from rain, ice storms, snow, winds, extreme ambient temperatures, freezing fog, flooding or frost and other extreme conditions.
- ***Defective Equipment:*** customer interruptions resulting from equipment failures including circuit breaker or protection failure due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.
- ***Foreign Interference:*** customer interruptions with causes beyond the control of the Distributor such as birds, animals, vehicle collisions, dig-ins, vandalism, sabotage and foreign objects.
- ***Human Elements:*** customer interruptions resulting from the interface of the Distributor's staff with the system such as incorrect records, incorrect use of equipment, incorrect construction or installation, incorrect protection settings, switching errors, commissioning errors, deliberate damage, or sabotage.
- ***Lightning:*** customer interruptions due to lightning striking the distribution system resulting in an insulation breakdown and/or flashovers.
- ***Loss of Bulk Supply:*** customer interruption due to problems arising in the bulk electricity supply system e.g. the transmission system.
- ***Planned Shutdown:*** customer interruption for the purpose of construction, preventive maintenance or repair where the customer has been given at least 24 hours notice. These include shutdowns by both the Distributor and TransGrid.
- ***Tree Contact**:* customer interruptions caused by faults due to trees or tree limbs contacting live circuits.
- ***Unknown/Other:*** customer interruptions with no apparent cause or reason.

Definitions Relating to Opex

- ***Direct costs:*** Direct costs are those directly related to operating and maintaining the network business of a DNSP: (a) including all costs that (i) are directly related to managing the system or (ii) are for the purpose of maintaining the service potential of system fixed assets; (b) excluding indirect costs, capital expenditure, depreciation, interest, amortisation of goodwill and intangibles, subvention payments, expenditure in relation to leased assets, transmission charges, avoided transmission charges, corporate tax, GST and other taxes except those incurred in the procurement and delivery of equipment.
- ***Indirect costs:*** Indirect costs are those *not* directly related to operating and maintaining the network business of a DNSP: (a) including all costs that (i) are *not* directly related to managing

the system or (ii) are for a purpose *other than* maintaining the service potential of system fixed assets; (b) excluding direct costs, capital expenditure, depreciation, interest, amortisation of goodwill and intangibles, subvention payments, expenditure in relation to leased assets, transmission charges, avoided transmission charges, corporate taxes, GST and other taxes except those incurred in the procurement and delivery of equipment.

2. GENERAL INFORMATION AND DOCUMENTATION

2.1 General Information and Documentation

The following general information and documentation is requested:

(a) Annual Reports and Interim Report

A copy of your annual report for each of the years ending 30 June 1998, 1999, 2000, 2001 and 2002 and your six-monthly interim report, if available, for the period ending 31 December 2002.

Please return the requested documents with your response (preferably in electronic form)

(b) Organisation Chart, Employee Numbers and Contracted Services

A copy of your current organisation chart or charts showing: the main structure of the organisation; details of the main planning and operational units; indicative staff numbers (full-time equivalents) in each business unit; and an outline of the arrangements in place for activities that are routinely contracted out.

Please return the requested documents with your response (preferably in electronic form)

(c) Corporate Plan

A copy of your corporate plan including overall corporate objectives, performance targets and corresponding performance to date.

Please return the requested document with your response (preferably in electronic form)

Please summarise below (preferably in less than one page) your corporate plan, with an emphasis on those parts of it that impinge on capital expenditures, the operation and maintenance of your fixed assets, and the achievement of your performance and service objectives.

Enter text here

(d) Asset Management Plan

A copy of your asset management plan. It is assumed that the plan will include substantially all of the following information:

(i) A statement of the background and objectives of the plan including its interaction with other corporate goals, business planning processes, and other plans;
(ii) Statement of asset management policies, systems and information;
(iii) Statement of refurbishment and replacement policies;
(iv) Description of the present network and assets including their general nature and location, identification of assets by category, their condition and age profile by category, present network and zone substation loading, available zone substation firm capacity, constraints;
(v) Statement of asset management practices by asset category, giving reasons for their adoption for each category;
(vi) Details of past and projected performance levels including losses, capacity utilisation, and reliability;
(vii) Justification for projected performance targets;

(viii) Actions taken and proposed for the introduction of new technology;
(ix) Actions taken and proposed to carry out environmental protection and safety improvement works;
(x) Other past and proposed improvement initiatives;
(xi) A review of progress against previous plans, both physical and financial, and an outline of the process for periodic review of the present plan.

Please return the requested document with your response (preferably in electronic form). If the document does not contain the information assumed, please provide it separately or in response to the questions that follow

(e) Long-Term Network Development Plan

A copy of your long-term network development plan including: your power system planning criteria, demand projections for each zone substation, a description of the forecasting methodology, a statement of the main forecasting assumptions made, typical daily and annual load curves for a representative mix of zone substations, development plans for networks at each voltage level, and cost estimates for the work recommended in the plan.

Please return the requested document with your response (preferably in electronic form). If the document does not contain the information assumed, please provide it separately or in response to the questions that follow

(f) Procurement and Construction Specifications

Copies of your standard procurement and construction technical specifications for the following works: underground cable supply and installation; overhead line supply and erection of materials; zone substation supply and construction; and outsourced operation and maintenance field services of the main types used.

Please return the requested documents with your response (in electronic or printed form)

(g) Network Performance Reports

A copy of each of your network performance reports submitted to the Ministry for the years 2000,2001 and 2002.

Please return the requested documents with your response (in electronic or printed form)

(h) Network Single-Line Diagrams and Maps

A copy of: (i) network single-line diagrams for: all sub-transmission voltage levels; and (ii) a selection of typical single-line diagrams for high- and low-voltage distribution networks for each type of network – rural, urban, overhead, underground – sufficient to demonstrate the concepts and layouts adopted. Note: if more than one design is prevalent on each type of network due to, for example, the merging of previously separate DNSPs, please submit drawings sufficient to illustrate each main type in service and indicate the approximate percentage of each type in each network.

Maps of a suitably large scale showing the geographical location of sub-transmission circuits.

Please return the requested documents with your response (preferably in electronic form)

(i) Maps Showing Location of Offices, Depots, Stores, Facilities Customers and Load Densities

Maps of suitably large scale showing: (i) the general location of your offices, depots, stores and facilities suitable to assess the scope and nature of your operations; and (ii) customer and load densities in your service area.

Please return the requested documents with your response (preferably in electronic form)

In the case of Country Energy, the load density maps may be for larger cities and towns only

2.2 Current Industry Codes of Practice

Please list below the current NSW or Australia-wide industry Codes of Practice that you work to. Do not list published standards such as AS or IEC.

List here

3. ASSETS IN SERVICE

3.1 Asset Quantities in Service

Please provide a schedule of assets in service at 30 June 2002 under the same headings as those in the tables in Appendix C of the NSW Treasury's *Draft valuation of electricity network assets – a policy guideline for NSW DNSPs, July 2001.* The tables are reproduced in Appendix 1 for ease of reference.

Append your schedule to the questionnaire

3.2 Age Profile of Assets in Service

Please complete Table 1 by entering the number of assets in service at 30 June 2002 commissioned in each period shown.

Table 1: Network Fixed Asset Age Profiles

Asset category	Unit	Number of assets commissioned in the period																	
		Pre-1921	1921-1925	1926-1930	1931-1935	1936-1940	1941-1945	1946-1950	1951-1955	1956-1960	1961-1965	1966-1970	1971-1975	1976-1980	1981-1985	1986-1990	1991-1995	1996-2000	2001-2002
132 kV tower lines	km																		
132 kV pole lines	km																		
132 kV U/G cables	km																		
66 kV lines	km																		
66 kV U/G cables	km																		
33 kV lines	km																		
33 kV U/G cables	km																		
11/22 kV lines	km																		
11/22 kV U/G cables	km																		
SWER lines	km																		
LV lines	km																		
LV U/G cables	km																		
Distribution transformers	No																		
132 kV CBs	No																		
66 kV CBs	No																		
33 kV CBs	No																		
11/22 kV CBs	No																		
Other distribution switchgear (all voltages)	No																		
Service connections	No																		
Revenue meters & load control relays	No																		

4. GENERAL STATISTICS AND PERFORMANCE DATA

4.1 General Statistics and System Performance Data

Please complete Tables 2 and 3 below, and Schedules 3 and 4 in the accompanying template, with data on your system and its performance, both historical and projected, to show past and projected characteristics and efficiency.

Please note the definitions in Section 1.9 of this questionnaire, those at the end of Schedule 4 of the template, and those in the footnotes to the table.

Table 2: General Statistics and System Performance Ratios

If considered appropriate, DNSPs may provide additional tables for particular areas with discernibly different characteristics as well as a table for the whole network.

FY ending 30 June ->	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Basis of determination	actual	actual	actual	actual	est.	est.	est.	est.	est.	est.	est.
Dollars used a/	nominal	nominal	nominal	nominal	real	real	real	real	real	real	real
Part A: General Statistics and Ratios											
Total service area (sq km)											
Total system length (km) b/											
Percent of total system length underground (%)											
Maximum demand (MW)											
Maximum demand (MVA)											
Energy entering the system (GWh)											
Energy sold (GWh)											
Annual load factor (%)											
Employee Numbers (full-time equivalent, year-end):											
Network											
Retail											
Non-regulated business											
Total											
Customers connected (No)											
Customer density (customers per km of system length)											
Customer density (customers per sq km of service area)											
Customers per employee (network)											
continued …											

a/ 'Nominal' refers to dollars of the designated year: 'real' refers to year 2003 dollars. b/ See the definition in Section 1.9

Table 2: General Statistics and System Performance Ratios (contd)

FY ending 30 June ->	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Basis of determination	actual	actual	actual	actual	est.	est.	est.	est.	est.	est.	est.
Dollars used a/	nominal	nominal	nominal	nominal	real	real	real	real	real	real	real
Part C: Capacity Utilisation											
Overall power transformer capacity (Nameplate MVA)											
Corresponding utilisation ratio (%) b/											
Substations transforming to an intermediate voltage level:											
Total load transferred through these substations (MVA)											
(n-1) nameplate capacity of transformers (MVA)											
Corresponding utilisation (%)											
Substations transforming to distribution voltage:											
Total load transferred through these substations (MVA)											
(n-1) nameplate capacity of transformers (MVA)											
Corresponding utilisation (%)											
Distribution substations:											
Total system MD less HV customer demand (MVA)											
Distribution transformer capacity (MVA)											
Utilisation ratio (%)											
Part D: Network Investment											
Total network investment at replacement cost ($ m) c/											
Corresponding investment per MVA of MD ($ 000 / MVA)											
Total network investment at DRC c/											
Corresponding investment per MVA of MD ($ 000 / MVA)											
Part E: Energy Losses											
Energy losses as percentage of energy entering the system											

a/ 'Nominal' refers to dollars of the designated year: 'real' refers to year 2003 dollars. b/ System maximum demand in MVA divided by sum of installed transformer capacity nameplate ratings in MVA. c/ Based on DNSP asset revaluations presently being completed.

4.2 Analysis of Interruptions by Cause and Area

Please complete Table 3 below with data on the analysis of interruption statistics by cause for your urban and rural networks separately. Please note the definitions of *urban* and *rural* at the end of Schedule 4 of the template and the definitions of the nominated causes of interruption in Section 1.9 of this questionnaire.

'Standard' data as defined in Schedule 4 of the template should be entered except that transmission interruptions should be added under the heading "loss of bulk supply".

Table 3: Analysis of Interruptions by Cause and Area

YE 30 June ->	SAIDI 2001	SAIFI 2001	CAIDI 2001	SAIDI 2002	SAIFI 2002	CAIDI 2002
Planned Shutdown						
Urban						
Rural						
Loss of Bulk Supply						
Urban						
Rural						
Tree Contact						
Urban						
Rural						
Lightning						
Urban						
Rural						
Defective Equipment						
Urban						
Rural						
Adverse Weather						
Urban						
Rural						
Adverse Environment						
Urban						
Rural						
Human Element						
Urban						
Rural						
Foreign Interference						
Urban						
Rural						
Unknown / Other						
Urban						
Rural						
Total Urban – all causes						
Total Rural – all causes						
Total – all causes						
Total excluding loss of bulk supply *a/*						

a/ Please check that these figures match the 'standard' data entered in the template, Schedule 4.

4.3 Analysis of Reliability of Circuits

In addition to the information requested in Schedule 4 of the template, please complete Table 4 by entering the number of faults per 100 km of circuit at each voltage level for the years indicated. The number of faults should be split between those due to defective equipment and other causes.

Table 4: Analysis of Faults per 100 km of Circuit by Voltage and Type

(Number of faults)

YE 30 June ->	Defective equipment 2001	Other causes 2001	Defective equipment 2002	Other causes 2002
132 kV overhead lines				
132 kV underground cables				
66 kV overhead lines				
66 kV underground cables				
33 kV overhead lines				
33 kV underground cables				
22/11 kV overhead lines				
22/11 kV underground cables				
SWER overhead lines				
LV overhead lines				
LV underground cables				

Please add any explanatory notes here:

Enter text below

4.4 Analysis of Losses

Please complete Table 5 with an analysis of energy losses on your system, including both calculated and estimated components, for the years indicated.

Table 5: Analysis of Energy Losses as a Percentage of Energy Input

YE 30 June ->	1998	1999	2000	2001	2002
Total a/					
Sub-transmission losses (calculated)					
Transformer losses (calculated)					
High voltage distribution losses (calculated)					
Distribution transformer losses (estimated)					
Low voltage losses (estimated)					
Unaccounted for balance including theft					

a/ Determined from metering and billing records. Please check that the totals match the figures entered in Table 2.

4.5 Network Utilisation

The following supplementary information on the utilisation of the sub-transmission and high voltage distribution networks is requested: (i) *Sub-transmission networks:* it is assumed that power system analyses will be available sufficient to demonstrate network utilisation under normal and contingency conditions. A summary of the studies will be requested, together with power flow and voltage diagrams (PSS/U or PSS/E drawing or similar); (ii) *High voltage distribution:* as above but power flow and voltage diagrams will not be requested.

Please return the requested document with your response (preferably in electronic form)

4.6 Zone Substation Utilisation

Please complete Table 6 for each zone substation that you own for the year ending 30 June 2002.

Table 6: Zone Substation Firm Capacities – 2002 Data

Substation name	Transformer nameplate ratings (Give number of transformers and rating of each in MVA)	Can substation be backed up through HV dist. network (Yes, No, Partially)	Substation firm capacity (MVA)	Peak demand (MVA)	Surplus capacity irm cap – eak dmd) (MVA)	Month of peak demand	Annual load factor (%)
	Example: 3x50 + 1x100						

Please define your interpretation of *firm capacity* below:

Enter your definition here

Please then complete Table 7 for the same zone substations using data at the end of your long-term planning period. Note: a 10-year planning period is suggested for the purpose of this assessment with data entered in Table 7 for the year ending 30 June 2014.

Table 7: Zone Substation Firm Capacities at End of Planning Period – YE 30 June 2014

Substation name	Transformer nameplate ratings (Give number of transformers and rating of each in MVA)	Can substation be backed up through HV dist. network (Yes, No, Partially)	Substation firm capacity (MVA)	Peak demand (MVA)	Surplus capacity irm cap – eak dmd) (MVA)	Month of peak demand	Annual load factor (%)
	Example: 3x50 + 1x100						

Please comment below on the actions you envisage where firm capacity is presently inadequate or is expected to be, by the end of the planning period assumed in this assessment:

Enter text here

5. DNSP's DEMAND FORECAST

5.1 Forecast of Demand and Customer Numbers

Please enter in the template your forecast of customer numbers and demand by tariff category for all years up to and including YE 30 June 2014 for low, medium and high growth scenarios.

Please enter this information in the template

Please then answer the following supplementary questions to help us interpret of your forecast:

Is your forecasting model based on historic trends? Yes/No/Partially _______

If yes or partially, please give explanatory details below.

Enter text here

Does it use econometric data, e.g. population forecasts, GDP forecasts? Yes/No ____

Assuming so, please give details of the main variables and coefficients below.

Enter text here

Does it take account of the probability of different ambient temperature or other meteorological factors? Is so, explain how. Yes/No ____

Enter text here

Is end-use forecasting for any sectors, e.g. appliance penetration? Is so, explain. Yes/No ____

Enter text here

Describe any other important features or parameters of the model.

Enter text here

Does the model forecast network demands by area or only for the whole network? ___________

Is a forecast made for each zone substation separately? Yes/No ____

Assuming the answer to this question is *yes*, please complete Table 8 below.

Table 8: Forecast Rate of Growth in Demand at Zone Substations

Substation name	Forecast average rate of growth in demand from 2003 to 2007 (% p.a.)	Forecast average rate of growth in demand from 2008 to 2012 (% p.a.)

5.2 *Demand-Side Management*

Please give the following details of the type of load control system used and the number and general location of plants installed:

Total controlled load ______ MW

Type of load controlled ______________________

Ripple control system? Yes/No ____

Pilot wire system? Yes/No ____

Time clocks? Yes/No ____

Agreements for demand reductions on request? Yes/No ____

If a mixture of systems, please indicate the number, general location and impact on demand of each.

Enter text here

Please list any other demand side management systems, projects or programmes in place or proposed for introduction in the period up 2011/12, including any new tariff, quantifying their expected impact on capex.

Enter text here

5.3 *Distributed Generation and Other Non-Network Solutions*

Please give details below of all distributed generation and other non-network projects in operation or being considered for introduction in the period up to the year 2014 to the extent that you are aware of them and describe their expected impact on your capex.

Enter text here

6. INFORMATION FOR INDEPENDENT DEMAND FORECAST

6.1 Historical Data

Meritec is required to review the demand forecasts of the DNSPs in order to help form a view on their reasonableness although it may choose to adopt the DNSPs' forecasts if appropriate. For this purpose, we may use a disaggregated forecasting model, considering each main market sector – residential, commercial, industrial, etc. The model will project energy consumption first, based on population trends, changes in specific consumption, GDP growth, demand and price elasticity and other relevant factors, and will then calculate peak demands taking into account changes in the time of year or day of demand, coincidence factors, load factors, etc.

Please complete Table 9 below with the data requested for this purpose. Information supplied in response to Section 5 will also be taken into account.

Note 1: Data for various of the DNSP's tariff categories may be used as a proxy for the market sector data requested provided the load is sufficiently representative of the sector.

Note 2: The attributes to be reported under *Trends* include changes in load characteristics, changes in the time of peak demand, rates of growth in new connections and sales and the like, expressed either in GWh or percent change.

Note 3: 'Rural' is defined in the notes at the end of Schedule 4 of the template.

Table 9: Historical Demand Data and Related Factors

YE 30 June ->	1998	1999	2000	2001	2002	2003 Est.
Customer numbers						
Residential						
Commercial						
Industrial						
Rural						
Other						
Total						
Energy sales (GWh)						
Residential						
Commercial						
Industrial						
Rural						
Other						
Total						
System maximum demand in summer (MVA)						
System maximum demand in winter (MVA)						
Distributed generation in service at the time of system maximum demand (MVA)						
System maximum demand in summer (MW)						
System maximum demand in winter (MW)						
Annual system load factor						
Month of system maximum demand						

Population in service area (2001 census) Projected population growth rates to 2014 GDP for your service area ($billion in nominal dollars) *Trends in each market sector:* Residential Commercial Industrial Rural Other Total *Please indicate your view on likely future trends:* Residential Commercial Industrial Rural Other Total Please provide any other data or comments that you consider relevant, highlighting any matters that you feel important						

6.2 Daily Load Curves

Please complete Table 10 by entering hourly information for the day of the system summer and winter peaks in 2002 and, to the extent that information is available, for different market sectors for the same year.

Note: The headings in the table refer to the predominant type of load to be described. It is suggested that a representative selection of feeder loads be used as the source.

Table 10: Daily Load Curves in YE 30 June 2002

(Maximum demand in MW)

Hour	Summer total	Winter total	Summer residential	Winter residential	Summer commercial	Winter commercial	Summer industrial	Winter industrial
0100								
0200								
0300								
0400								
0500								
0600								
0700								
0800								
0900								
1000								
1100								
1200								
1300								
1400								
1500								
1600								
1700								
1800								
1900								
2000								
2100								
2200								
2300								
2400								

6.3 *Customer Base*

(a) Customers by Sales Volume

Please complete Table 11 by entering the number of customers in each indicated band of sales for the year ending 30 June 2002.

Table 11: Customer Numbers by Sales Volume

Range of annual sales (kWh)	Number of customers	Total annual sales (GWh)
Small (0-40,000)		
Medium (40,000 – 160,000)		
Large (>160,000)		
Total		

(b) Largest Customers

Please complete Table 12 by entering the requested details of your 20 largest network customers at 30 June 2002 in terms of energy delivered:

Table 12: Details of 20 Largest Customers

Customer No	Industry	General location	Approximate maximum demand (MVA)	Approximate annual energy sales (GWh)
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				

7. ACTUAL v. PROJECTED CAPEX FOR PERIOD 1998 TO 2003

7.1 Definition of Capital Expenditure

Please state below your definition of capital expenditure (capex) with reference to the NSW Treasury's *Guidelines for capitalisation of expenditure in the NSW public sector, June 2000* (the *Capitalisation Guidelines).*

Enter text here

Because the *Capitalisation Guidelines* were prepared for use throughout the public sector, please confirm that you apply them to your electricity network business as follows (if not, please give details of your method of application):

Enter text here

(a) Expenditure over $500 is capitalised where: (i) the asset is intended for more than 12 months' use; and (ii) the minimum asset unit created appears on your fixed asset schedule (note: expenditure which forms a component of a minimum asset will be maintenance expenditure: for example the replacement of cross-arms which form part of the asset unit *poles*)
Yes/No ____

(b) The following expenditure is treated as capex:

(i)	Purchase, installation and replacement of transformers	Yes/No ____
(ii)	Purchase, installation and replacement of substation equipment	Yes/No ____
(iii)	Pole replacements	Yes/No ____
(iv)	Conductor replacements and laying new cable	Yes/No ____

(c) The following expenditure is treated as opex:

(i)	Oil changes and relocation of transformers	Yes/No ____
(ii)	Moving lines without adding new poles; relocating cables	Yes/No ____
(iii)	Replacing broken and damaged cross-arms and insulators	Yes/No ____
(iv)	Repairing cables and replacing cable lengths of less than 5 metres	Yes/No ____
(v)	Temporary or remedial line costs	Yes/No ____
(vi)	The cost of dismantling and removing assets	Yes/No ____
(vii)	Penalty costs incurred by DNSPs for fixed asset additions or replacements performed by contractors outside normal working hours to the extent that the costs exceed standard costs	Yes/No ____

7.2 Actual v. Projected Capital Expenditures from 1999 to 2003

Please enter your actual capex in the years ending 30 June 1998 to 30 June 2003 inclusive in the accompanying template under the requested headings, noting the further instructions on the first page of the template. Please also enter the capex projections that you made at the time of IPART's 1998 capex review for comparison with your actual expenditures.

Note: Your actual capex entered must align with the capex numbers provided to IPART in the regulatory accounts for those years. If they vary, the differences must be explained.

Please then identify in the template and explain below the reasons for changes in expenditure of more than 10% in any year that arose due to the factors listed below:

(a) Changes in projected or actual load or in load patterns during the period;

Enter text here and complete the template

(b) Changes in installed unit costs from those assumed in your 1998 projections (Note: this section of the questionnaire is not to be taken as an endorsement by Meritec or IPART of new asset values);

Enter text here and complete the template

(c) The need for compliance with new statutory obligations, if any, introduced during the period;

Enter text here and complete the template

(d) The advancement or deferral of expenditures during the period other than for reasons already listed;

Enter text here and complete the template

(e) Adoption of new policies, planning criteria or designs following your amalgamation with other DNSPs (please state the instance and year of amalgamation in each case);

Enter text here and complete the template

(f) Planning or budgeting errors (e.g. cost under-estimation, failure to plan to avoid construction bottlenecks, etc);

Enter text here and complete the template

(g) The extent to which Y2K or full retail contestability costs added to expenditure (indicate what you submitted to IPART for approval in respect of Y2K and FRC costs and what has been approved by IPART for FRC costs);

Enter text here and complete the template

(h) The extent to which changes in your policies for overhead cost allocation increased the cost of capital works;

Enter text here and complete the template

(i) The extent to which non-network solutions and demand-side management measures reduced capex;

Enter text here and complete the template

(j) Other factors, for example: the net cost after insurance recoveries of remedying damage.

Enter text here and complete the template

8. CAPITAL EXPENDITURE PROJECTIONS

8.1 Network Planning Criteria

Please answer the following questions about your network planning criteria:

(a) Documentation

Are your network planning criteria documented for sub-transmission systems, high voltage distribution systems and low voltage distribution systems? Assuming so, please enter details here if the criteria are not described fully in your long-term network development plan (see Section 2.1).

Enter text here

What planning period is assumed in your long-range plan? __________ years

When were your planning criteria last reviewed comprehensively and what conclusions did the review reach? Have the conclusions of the review been incorporated into your standard practice?

Enter text here

(b) Security of Supply

Are your security of supply criteria deterministic, probabilistic or both? __________________

If deterministic, do they include a statement of required restoration times? __________________

Do your required restoration times vary with load magnitude? __________________

If a probabilistic approach is used alone or as well, how is it applied? ______________________

What contingencies are excluded, e.g. zone substation bus faults? ______________________

Please complete Table 13 below by entering details of your deterministic planning criteria. Change the format of the table to suit your own criteria.

Table 13: Deterministic Security of Supply Criteria for Network Planning Purposes

Magnitude of interrupted demand (MVA)	Minimum demand to be met after the first outage and after the second	Restoration times for remaining load after first and second outage

(c) Permissible Plant Loading

What are your detailed criteria for the permissible maximum loading of network elements and equipment including cables, lines and transformers?

Enter detailed text here (compliance with specific IEC or Australian standards concerned with permissible plant loadings is acceptable, for example, for transformer and cable loadings, but where you do not adopt this approach, please give details of your approach)

What specific or local ambient conditions and maximum permissible operating temperatures are assumed in applying the criteria e.g. maximum ambient temperature, minimum wind speed, hot spot temperature, etc?

Enter text here

Please list below the voltage regulation limits assumed for planning purposes under normal and contingency conditions (if more than one level of contingency is considered, please give details for all levels):

Zone substation bus (HV level)	________ %
Zone substation bus (distribution level)	________ %
Low voltage feeder (source)	________ %

Please list below the target energy losses assumed for planning purposes:

Sub-transmission networks	________ %
Transformers	________ %
HV distribution networks	________ %
Distribution transformers	________ %
Low voltage networks	________ %

Please state below the peak load power factor target at zone substations assumed for planning purposes: ________

8.2 Optimality of Design and Construction Practices

To what extent are your cable, conductor and equipment sizes and circuit designs optimised in your view?

Enter text here

To what extent are your procurement and construction specifications optimised in your view?

Enter text here

When were these matters last reviewed comprehensively and what conclusions did the review reach? Have the conclusions of the review been incorporated into your standard practice?

Enter text here

8.3 Unit Installation Costs

Please confirm that all unit installed costs and standard lives at 30 June 2002 assumed when preparing your capex projections are in accordance with Appendix C of the NSW Treasury's *Guidelines:* Yes/No ____

If No, please enter details and an explanation in respect of each departure in Table 14 below.

Note 1: The categories entered in the table should match those in Appendix C of the *Guidelines.*

Note 2: Unit installation costs (unit replacement costs in the *Guidelines*) should include all costs in accordance with the requirements for determination of cost in the *Guidelines*. Unit costs within 10% of the figure or range possible using standard *Guideline* costs together with the appropriate and reasonable application of multipliers as permitted in the *Guidelines* are not considered to constitute a departure for the purpose of completing this table.

Note 3: Please give an analysis of the impact of relevant labour, plant, material and overhead cost movements when explaining your departures.

Note 4: This section of the questionnaire is not to be taken as an endorsement by Meritec or IPART of new asset values.

Table 14: Departures in Unit Installed Costs or Economic Lives from Treasury Guideline Unit Replacement Costs

Asset Category and description	Unit	Notes	Standard installed cost at 30 June 2002 ($ 000)	Standard life (years)

To what extent are the unit installation costs used for your capex projections optimal in your view? What evidence do you have available to support your view?

Enter text here

When were your unit costs last reviewed comprehensively and what conclusions did the review reach? Have the conclusions of the review been incorporated into your standard practice?

Enter text here

Did this review include a review of all design aspects, project management practices, the incorporation of competitive bidding procedures, the confirmation that bid evaluation processes are robust, and that new technology and innovative design approaches have been incorporated where appropriate?

Enter text here

8.4 Replacement Capex

Please describe below your asset replacement policies for each asset category if they are not described in your asset management plan (see Section 2.1(d)).

Enter text here

Please confirm that your replacement capex is matched to the age profiles of your assets as indicated in Table 1. If not, give details of your approach to its determination.

Enter text here

Please give details of any comprehensive asset condition assessment surveys carried out since 1998 if not described in your Asset Management Plan and confirm that the findings of the surveys have been taken into account in your plans.

Enter text here

What are your wood-pole testing policies?

Enter text here

8.5 Impact of Statutory Obligations on Capex

Please list any statutory obligations, including but not limited to safety, environmental protection and quality of supply that influence your capex and indicate their impact over the period for which capex is to be projected (up to and including 2014).

Enter text here

Do any local government authorities (e.g. councils) impose requirements that influence capex (e.g. new circuits in certain areas to be underground)? Please give specific details and indicate whether the obligations are mandatory or discretionary.

Enter text here

8.6 Capex Evaluation and Approval Processes

Describe, preferably in less than one page, the capex evaluation and approval processes followed from project identification to approval.

Enter text here

Please list the parameters used in your economic and financial analysis of projects including the discount rate assumed and the number of years of operation included in the analysis.

Enter text here

Please confirm that operation and maintenance costs are taken into account in your evaluation of capex projects. Yes/No ____

Please confirm that the benefits of loss reduction are included and describe the methodology used. Yes/No ____

Enter text here

Please describe how the benefits of system reliability improvement are quantified in the analysis.

Enter text here

What other benefits are taken into account in your analysis?

Enter text here

8.7 Capex Projections

Please now complete Schedule 1 of the accompanying template giving details of your projected capex under the requested headings for the period from and including the year ending 30 June 2004, noting the further instructions on the first page of the template.

Include the cost of all works required to meet statutory obligations, comply with accepted industry safety standards and comply with accepted industry codes of best practice.

9. OPERATING AND MAINTENANCE COSTS

9.1 Cost-Based Performance Measures and Analysis

Please complete Schedule 2 of the template, noting the definitions of direct and indirect costs in Section 1.9 of this questionnaire. Because of possible inconsistencies in the way DNSPs classify indirect costs, please then complete the remainder of Schedule 2 by summing total direct and total indirect costs and using the appropriate denominators to derive the other cost-based performance measures asked for.

Note 1: please use either real or nominal dollars in each year as requested in the table. We will make adjustments for inflation as required. Please note the definitions in footnote a/ in the table and enter your inflation assumptions in Schedule 1A of the template. Note the instructions in that schedule.

Note 2: it is important that you provide the analyses exactly as requested, noting the definitions used. Any explanatory notes or assumptions that you wish to record can be inserted on this page in the space provided below.

Insert explanatory text here if required

9.2 Operating and Maintenance Staff and Facilities

Please complete Table 16 below with details of your operating and maintenance facilities.

9.3 Reconciliation of Costs and Data and Changes in Cost Allocation Methods

Please provide a reconciliation of the costs and data entered in Schedule 2 of the template with that entered in IPART's Information Request so that their composition, the allocation of overheads, and the apportionment of costs between different business units including network and non-network units can be checked. The reconciliation should include details of the adjustments made to remove capitalised components from the figures entered in Schedule 2 for opex.

Please also provide a reconciliation of the breakdown of employee numbers given in Table 16 with your published employment data.

Please insert your reconciliation in Schedule 4 of the template

Please also state below any material changes in cost allocation policies that have been made during the period 1999 to 2003 and indicate their impact on the data you have entered.

Please enter text here

Table 15: Cost-Based Performance Measures and Analysis

(This table has been deleted: see Schedule 2 of the template instead)

Table 16: Operating and Maintenance Staff and Facilities

Measure YE 30 June ->	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Basis of determination	actual	actual	actual	actual	est.	est.	est.	est.	est.	est.	est.
Part A: Analysis of Operating and Maintenance Function Employee Numbers by Employment Category											
(Full-time equivalent, year-end employees: own staff and contract labour only including the staff of subsidiary companies involved in O and M but excluding labour engaged by outside contracted services companies)											
Managerial and professional											
Technician grade engineering, drafting and other											
Administrative and secretarial											
Field services											
Total											
Part B: General Data											
Number of field service depots	n.n.										
Average service area covered by each (sq km)	n.n.										
Number of workshops for transformer overhauls	n.n.										
Number of stores of significant size for network materials	n.n.										
Percentage of activities carried out using HV live-line or glove and barrier techniques instead of dead line	n.n.										
Number of qualified staff for this work	n.n.										
Specialised cable jointing skills available (yes/no) c/	n.n.										
Number of qualified staff for this work	n.n.										

a/ 'Nominal' refers to dollars of the designated year: 'real' refers to year 2003 dollars. c/ 132 kV and above. n.n. Data is not needed for these years.

9.4 Unsatisfactory Feeders

Please provide details below of the number, general location and performance of unsatisfactory feeders – that is, feeders of unsatisfactory reliability – reported or to be reported to the Ministry of Energy and Utilities for the year ending 30 June 2002.

Note: if this information is included in your Network Performance Report or other standard documentation, please include a cross-reference to it here.

Enter text and details here

9.5 Maintenance Practices

Please summarise your principal asset maintenance practices for each asset category by completing Table 17, entering 'Yes' in the columns where appropriate. Add explanatory notes below the table if required.

Note 1: Where maintenance for a particular asset category is reactive only – in other words, assets are fixed only when they break and no preventive work is carried out – enter 'yes' in the *reactive maintenance* column. Otherwise, please leave that column blank as it is assumed that, in all asset categories, in addition to preventive work, everyone fixes things that have broken.

Note 2: Please enter only the principal maintenance practice in each case.

Table 17: Summary of Principal Maintenance Practices

Asset category	Reactive maintenance only	Preventive		
	(see note 1)	Condition-driven	Reliability-driven	Periodic (Fixed Interval)
Sub-transmission circuits				
Steel tower or mast lines				
Wood pole lines				
Concrete pole lines				
Cables				
Zone substations				
Outdoor structures				
Transformers				
Circuit breakers				
Indoor equipment				
Other equipment				
HV distribution circuits				
Steel tower or mast lines				
Wood pole lines				
Concrete pole lines				
Cables				
Network HV switchgear including CBs				
Distribution substations				
LV distribution circuits				
Steel tower or mast lines				
Wood pole lines				
Concrete pole lines				

Cables Other LV equipment Revenue meters and load control relays				

Please add any further explanatory notes below and give details if practices vary within each category, e.g. for small v. large distribution transformers.

Enter text here

What proportion of your line maintenance is carried out using live-line or glove-and-barrier techniques? And what are your plans to expand their use to reduce planned interruptions?

Enter text here

9.6 Operational Logistics and Practices

When did you last carry out a comprehensive review of your operational logistics (inventory, procurement, fleet and plant management, staff numbers and deployment) and practices (including shut-down management processes)? Have the conclusions of the review been incorporated into your standard practice? Give details below.

Enter text here

When did you last carry out a comprehensive review of your operational policies including the degree of automation on the system and the introduction of new technology to improve reliability (e.g. fault locators, transient current indicators and electronically controlled voltage regulators on rural feeders, and modern electronic protection)? Have the conclusions of the review been incorporated into your standard practice? Give details below.

Enter text here

If you outsource a significant proportion of your operation and maintenance work, are you satisfied that you have adequate project management, contract administration, compliance auditing and cost review measures are in place and that the contracted rates are competitive? Have you reviewed these matters recently? Have the conclusions of the review been incorporated into your standard practice? Give details below.

Enter text here

9.7 Training Programmes

Please describe briefly the training programmes you have in place for field services staff including training in live-line and glove-and-barrier work. What further training is proposed to make efficiency and cost reduction gains? Give details below.

Enter text here

9.8 Asset Knowledge

Please describe the nature of your geographic information systems and other databases used for operation and maintenance purposes and for helping determine capex and renewal programmes.

Enter text here

How satisfied are you that the data contained in the systems is accurate and up-to date and that your knowledge of the asset base is sufficiently comprehensive for your purposes? If you have reservations about your level of asset knowledge, or if you face data constraints, what are you doing about it?

Enter text here

9.9 Cost Efficiencies Arising from Integration

It is anticipated that all DNSPs will have achieved savings and improved service levels following the reform of the electricity sector and the integration of DNSPs with others from around 1995 and again, in Country Energy's case, after 1 July 2001. Please summarise the main integration activities, state of completion of each, and financial benefits or costs realised to date. Please also summarise the remaining actions to be taken and expected financial benefits.

Enter text here

Would it be advantageous to further rationalise equipment sizes and designs? Yes / No _____

If so, is this being actioned? Yes / No _____

Give details

9.10 Service Standards and Actions

You entered your service standard targets in Schedule 4 of the template. Please now complete Table 18 below with further details of your service standards, their quality characteristics and related performance indicators, your current and targeted levels of service, the proposed performance measurement procedures, and the actions you propose to take to achieve the targets. Make modifications to the standards, characteristics and indicators already entered in the table where required to describe your own policy and plans.

Table 18: Summary of Key Service Standards and Actions

Service standard	Quality characteristic	Performance indicator	Current level of service 2002/03	Target level of service 2008/09	Performance measurement procedure	Actions to achieve targeted performance
Safety and environment	Safety of network assets Environmental compliance	No of network hazards identified No of environmental hazards identified				
Quality	Voltage, wave-form Work quality compliance with standards	No of customer enquiries & complaints Percentage compliance with m'tce standards				
Reliability and security	Incidence, frequency and duration of outages by cause	Performance indicators in Table 2				
Network delivery efficiency	Losses and utilisation	System performance indicators in Table 2				
Economic effectiveness	Level of direct and indirect costs	Cost-based indicators in Schedule 2 of the				

		template				
Responsiveness	Supply restoration Planned interruption New reticulation Quality complaints	Restoration response times Notice period Installation time Response time				

Please then enter below a justification for your choice of performance targets.

Enter text here

Please ensure that the responses to this question are coordinated with the content of your Asset Management plan and with your entries in Table 2 of the questionnaire and Schedule 2 of the template.

9.11 Comparison of Actual and Projected Opex for 1999 - 2003

Please now complete Schedule 2 of the template giving details of your projected and actual opex under the requested headings for the years ending 30 June 1999 to 2003 inclusive, noting the further instructions on the first page of the template. The projected opex figures should be those you gave to IPART at the time of the 1998 review.

Note: it is appreciated that figures for the year ending 30 June 2003 will be estimates based on the results of the year to date.

Please identify the reasons for any major departures from the projections under the following headings and give reasons:

(a) Please identify, separately, opex incurred in relation to Y2K and full retail contestability during the period indicating in each case the expenditures each year and what was approved by IPART in respect of FRC. Indicate the extent to which they exceeded your projections under each of these categories;

Enter text here and complete the template

(b) Please identify the nature and extent of opex arising each year during the period as a direct result of the amalgamation of your DNSP with others: for example, redundancy payments and other costs of rationalisation or reorganisation (Note: this will apply to Country Energy but also, to a lesser extent, to Energy Australia and Integral Energy as the residual effects of their earlier amalgamations were worked through);

Enter text here

(c) Please identify opex resulting from the need to comply with new statutory obligations that came into effect during the period and describe the nature of the obligations;

Enter text here

(d) Please identify opex resulting from non-network solutions and the extent to which it exceeded your projections;

Enter text here

(e) Please explain the balance of the difference between your projected and actual opex.

Enter text here and complete the template

Please reconcile all data with your submissions to IPART and your responses to the *Information Request.*

9.12 Opex Projections

Please now complete Schedule 2 of the template giving details of your actual and projected opex, noting the further instructions in the template. Please give any necessary explanatory notes below or in the template.

Enter text here

10. INTER-COMPANY TRANSACTIONS

10.1 Inter-Company Transfers and Cost Allocations

In addition to the reconciliation requested in Section 9.3 of the questionnaire, please answer the following questions to help ensure that we have a full understanding of the cost structure and operations of your regulated network business:

(a) Inter-company transactions, goods and services provided to the regulated network business by internal business units: please describe your group structure including entities in which you have an equity holding of 10% or more.

Enter text here or attach a schedule referenced here

(b) Please list all transactions related to opex or capex greater than or equal to $50,000 for Energy Australia, $20,000 for Integral Energy and Country Energy, and $5,000 for Australian Inland Energy between the regulated network business and the entities listed in response to (a) above for the years ending 31 June 2001 and 2002.

Enter text here or attach a schedule referenced here

(c) For goods and services related to opex or capex provided to the regulated network business directly or indirectly by the entities listed in response to (a) above, please provide details of the prices charged and the underlying costs incurred by the entities for providing such goods and services.

Enter text here or attach a schedule referenced here

(d) For goods and services related to opex or capex provided by the regulated network business to these entities and other business units within the group, please provide the prices charged by regulated network business and costs, direct and indirect allocated to the goods and services sold.

Enter text here or attach a schedule referenced here

(e) For goods and services related to opex or capex provided by the internal business units/profit centres to the regulated network business, please provide the prices charged by the business units and the underlying direct and indirect costs incurred by the business units/profit centres for providing such goods and services.

Enter text here or attach a schedule referenced here

APPENDIX 1: TABLES FROM DRAFT TREASURY VALUATION GUIDELINES

The following tables are re-produced without change from Appendix C of the NSW Treasury's *Valuation of electricity network assets – a policy guideline for NSW DNSPs (Draft), July 2001* for ready reference, noting that the text in Appendix C of the *Guidelines* needs to be referred to when interpreting the tables or making comparisons with them.

Table 1: Table of Standard Replacement Costs and Effective Lives

Asset Category and Description	Unit	Notes	Standard Replacement Cost ($000)		Standard Life (Years)	
					Wet Area	Dry Area
SUBTRANSMISSION LINES						
OVERHEAD LINES (132KV)						
132kV Double Circuit Steel Lattice Tower						
Rural Heavy – single conductor	km		436		60	
Rural Heavy – twin conductor	km		482		60	
Urban Heavy – single conductor	km		642		60	
Urban Heavy – twin conductor	km		688		60	
132kV Rural H Pole			Wood	Concrete		
Heavy	km		86	92	45	55
Medium	km		76	83	45	55
Light	km		70	77	45	55
132kV Rural Single Pole						
Light	km		56	59	45	55
132kV Urban Horizontal Post Insulator (single circuit)						
Heavy	km		96	104	45	55
Medium	km		89	98	45	55
Light	km		84	95	45	55
132kV Urban Horizontal Post Insulator (double circuit)		.				
Heavy	km		145	153	45	55
Medium	km		131	140	45	55
Light	km		121	130	45	55
UNDERGROUND CABLES (132kV)						
132 kV Underground Cable						
Medium	km		964		45	
132kV Terminations						
Overhead	No.		68		45	
Indoor	No.		76		45	

Asset Category and Description	Unit	Notes	Standard Replacement Cost ($000)		Standard Life (Years)	
					Wet Area	Dry Area
OVERHEAD LINES (66kV)						
66 kV Rural Lines			Wood	Concrete		
Heavy	Km		67	75	45	55
Medium	Km		59	68	45	55
Light	Km		53	59	45	55
66kV Urban Lines						
Heavy	Km		122	141	45	55
Medium	Km		117	134	45	55
UNDERGROUND CABLES (66kV)						
66kV Underground Cables						
Medium	Km		664		45	
66kV Terminations						
Overhead	No.		58		45	
Indoor	No.		37		45	
OVERHEAD LINES (33kV)						
33 kV Rural Lines			Wood	Concrete		
Heavy	Km		61	68	45	55
Medium	Km		55	63	45	55
Light	km		52	58	45	55
Extra-light	km		50	55	45	55
33 kV Urban Lines						
Heavy	km		101	121	45	55
Medium	km		96	116	45	55
Light	km		91	111	45	55
UNDERGROUND CABLES (33kV)						
33 kV Underground Cables						
Heavy	km		550		60	
Terminations						
Overhead	No		30		60	
Indoor	No		12		60	
EQUIPMENT (66kV & 33kV)						
Pilot Cables	km		30		60	
Regulators	No	a			60	
Air Break Switches 3 phase						
33 kV	No		11.5		35	

Asset Category and Description	Unit	Notes	Standard Replacement Cost ($000)		Standard Life (Years) Wet Area	Standard Life (Years) Dry Area
66 kV	No		18.1		35	
Fuses - 3 phase set						
33 kV	No		11.4		35	
Lines - 3 phase set						
33 kV	No		8.1		35	
66 kV	No	a			35	
DISTRIBITION OVERHEAD LINES						
SWER Lines						
Heavy	km		10.9		45	55
Light	km		10.4		45	55
11/22 kV Rural Lines - 3 Phase			Wood	Concrete		
Heavy	km		27.8	28.7	45	55
Medium	km		23.7	28	45	55
Light	km		21.8	24.5	45	55
Extra Light	km		12.7	14.7	45	55
Steel	km		9.8	11.8	45	55
11/22 kV Rural Lines - 3 Phase Underbuilt						
Heavy	km		19.3	20.6	45	55
Medium	km		18.7	19.1	45	55
Light	km		16.3	17.7	45	55
11/22 kV Rural Lines - 3 Phase Covered						
Heavy	km		59	64	45	55
Light	km		54	59	45	55
11/22 kV Urban Lines - 3 Phase						
Heavy	km		50	56	45	55
Medium	km		45	62	45	55
Light	km		42	60	45	55
11/22 kV Urban Lines - 3 Phase Underbuilt						
Heavy	km		32	41	45	55
Medium	km		28	38	45	55
Light	km		24	36	45	55
11/22 kV Urban Lines - 3 Phase Covered						
Heavy	km		76	92	45	55
Light	km		72	88	45	55
DISTRIBUTION UNDERGROUND CABLES						

Asset Category and Description	Unit	Notes	Standard Replacement Cost ($000)	Standard Life (Years) Wet Area	Standard Life (Years) Dry Area
11/22 kV Underground - 3 Phase					
Heavy	km		78	60	
Medium	km		76	60	
Light	km		72	60	
DISTRIBUTION EQUIPMENT					
Reclosers (11/22kV)		e			
● 3 Phase (hydraulic)	No		20	35	
● 3 Phase (electronic)			34	35	
Sectionalisers (11/22 kV)		e			
● 3 Phase	No		8	35	
Regulators	No		65	35	
Air Break Switches (11/22kV)					
3 phase top pole	No		5.6	35	
3 phase mid pole	No		5.2	35	
Links - 3 phase set					
SWER	No		1.2	35	
11/22 kV	No		1.5	35	
Fuses - 3 phase set					
11/22 kV	No		1.8	35	
DISTRIBUTION TRANSFORMERS (kVA)					
12.7 kV SWER Pole Mount					
16	No		2.1	35	45
25	No		2.4	35	45
100	No		8.3	35	45
Isolating	No		7.6	35	45
19.1 kV SWER Pole Mount					
16	No		2.6	35	45
25	No		2.9	35	45
Isolating	No		12.4	35	45
11/22 kV - 1 Phase Pole Mount					
16	No		1.8	35	45
25	No		2.3	35	45
63	No		3.5	35	45
11/22 kV - 3 Phase Pole Mount					
25	No		3.5	35	45

Asset Category and Description	Unit	Notes	Standard Replacement Cost ($000)	Standard Life (Years) Wet Area	Standard Life (Years) Dry Area
63	No		4.6	35	45
100	No		5.4	35	45
200	No		7.8	35	45
315	No		11.1	35	45
400	No		12.6	35	45
500	No		15.8	35	45
11 kV - Kiosk and Pad Mount					
315	No		13.8	45	
500	No		17.2	45	
750	No		22.9	45	
1000	No		26.9	45	
22 kV - Kiosk and Pad Mount					
315	No		16.4	45	
500	No		20.5	45	
750	No		30.0	45	
1000	No		33.9	45	
11 kV Cable Box					
500	No		19.9	45	
750	No		26.9	45	
1000	No		29.5	45	
1500	No		41.0	45	
33 kV - 1 Phase Pole Mount					
25	No		4.4	35	45
33 kV - 3 Phase Pole Mount					
25	No		6.3	35	45
100	No		8.7	35	45
200	No		10.9	35	45
315	No		12.9	35	45
DISTRIBUTION SUBSTATIONS (Excluding Transformers)					
12.7 kV SWER					
All sizes	No		4.7	40	
19.1 kV SWER					
All sizes	No		4.8	40	
11/22 kV - 1 Phase					
All sizes	No		5.7	40	

Asset Category and Description	Unit	Notes	Standard Replacement Cost ($000)	Standard Life (Years) Wet Area	Standard Life (Years) Dry Area
11/22kV - 3 Phase					
Less than 64 kVA	No		7.1	40	
64 kVA and above	No		8.2	40	
11/22 kV - Kiosk and Pad Mount					
Up to 500 kVA	No		27.7	40	
Greater than 500 kVA	No		33.4	40	
11 kV - Chamber Type (without LV ACB/protection					
1 Transformer	No		36	40	
2 Transformer	No		67	40	
3 Transformer	No		97	40	
4 Transformer	No		127	40	
11 kV - Chamber Type (with LV ACB/protection					
1 Transformer	No		95	40	
2 Transformer	No		140	40	
3 Transformer	No		195	40	
33 kV - 1 Phase					
All sizes	No		5.9	40	
33 kV - 3 Phase					
Less than 64 kVA	No		6.9	40	
64 kVA and Above	No		8.7	40	
LOW VOLTAGE					
OVERHEAD LINES (LV)					
LV Lines - 1 Phase					
All sizes	km		44	45	55
LV lines - 1 Phase covered					
All Sizes	km		18	45	55
LV – 1 Phase Underbuilt					
All sizes	km		16	45	55
LV – 1 Phase Underbuilt covered					
All Sizes	km		30	45	55
LV Lines 3 Phase					
All sizes	km		55	45	55
LV Lines - 3 Phase Underbuilt					
All sizes	km		21	45	55
LV Lines - 3 Phase Covered					

Asset Category and Description	Unit	Notes	Standard Replacement Cost ($000)	Standard Life (Years) Wet Area	Dry Area
<300A	km		51	45	55
>300A	km		61	45	55
LV Lines - 3 Phase Covered Underbuilt					
All sizes	km		20	45	55
UNDERGROUND CABLES (LV)					
LV Underground - 3 Phase					
Heavy	km		79	60	
Medium	km		70	60	
Light	km		60	60	
EQUIPMENT					
Links - 3 phase set	No		0.8	35	
CUSTOMER SERVICE CONNECTIONS					
Overhead					
All	No		0.23	35	
Service Pole	No		1.15	35	
REVENUE METERS AND LOAD RELAYS		d			
Load Relays					
AF Relay	No		0.14	25	
Time Switch	No		0.17	25	
LV Metering					
1 Phase	No		0.13	25	
3 Phase	No		0.42	25	
3 Phase CTs	No		0.86	25	
HV Metering					
HV Meter, VT and CT	No	a		25	
STREET & TRAFFIC ROUTE LIGHTING					
Traffic Wood Pole			1.7	20	
Traffic standard			4.2	20	
Street wood pole			0.9	20	
Street standard			2.2	20	
OTHER SYSTEM FIXED ASSETS					
CENTRAL FACILITIES					
SCADA	Lot	a		4	
Communications	Lot	a		7	

Notes:
a) No standard cost applied or where cost included should be treated as a benchmark only.
b) Wet areas are those where the long-term average annual rainfall is greater than 900mm.

Asset Category and Description	Unit	Notes	Standard Replacement Cost ($000)	Standard Life (Years) Wet Area	Dry Area
c) A 60 year life can be applied to substation buildings of brick or concrete block construction. A 40-year life applies to wood construction. d) Contestable metering is not included as a network asset. e) Recloser and sectionaliser rates include cost of pole.					

Table 2: Table of Standard Replacement Costs for CBD areas

Asset Category and Description (Note 1)	Unit	Notes	Standard Replacement Cost ($000)
SUBTRANSMISSION UNDERGROUND CABLES		2	
132 kV Underground Cable			
Extra Heavy	km		1,619
Heavy	km		1,314
66kV Underground Cables			
Extra Heavy	Km		1163
33 kV Underground Cables		3	
Extra Heavy	km		894
Medium	km		685
Light	km		670
DISTRIBUTION UNDERGROUND CABLES		4	
11/22 kV Underground - 3 Phase			
Extra Heavy	km		140
Extra Heavy and Heavy in one trench	km		185

Table 4 Standard Rates for Zone Substations

Asset Category and Description (Note 1)	Unit	Notes	Standard Replacement Cost ($000)	Standard Life (Years)
132 GIS – feeder, bus section or transformer	No	2	-	40
132 CB outdoor – feeder	No		375	40
132 CB outdoor – bus section	No		335	40
132 CB outdoor – transformer	No	3	425	40
132 CB outdoor – feeder or bus section (no CB)	No		175	40
132 CB outdoor – transformer feeder (no CB)	No	3	325	40
66 CB outdoor – feeder	No		330	40
66 CB outdoor – bus section	No		250	40

Asset Category and Description (Note 1)	Unit	Notes	Standard Replacement Cost ($000)	Standard Life (Years)
66 CB outdoor – transformer	No	3	280	40
66 outdoor – feeder (no CB)	No		170	40
66 outdoor – bus section (no CB)	No		130	40
66 outdoor – transformer (no CB)	No	3	200	40
66 capacitor bank	No	4	430	40
33 CB outdoor feeder	No		250	40
33 CB outdoor – bus section	No		200	40
33 CB outdoor – transformer	No	3	190	40
33 outdoor – transformer (no CB)	No	3	70	40
33 outdoor – transformer (expulsion fuse)	No		60	40
33 CB indoor – feeder	No		230	40
33 CB indoor – bus section	No			40
33 Capacitor bank	No	4	350	40
11/22 CB outdoor – feeder	No		90	40
11/22 CB outdoor – transformer	No		110	40
11/22 outdoor – feeder recloser	No		45	40
11/22 CB indoor – single feeder	No		45	40
11/22 CB indoor – double feeder single protection	No		80	40
11/22 CB indoor – double feeder double protection	No	5	90	40
11/22 CB indoor – bus section	No		80	40
11/22 CB indoor – transformer	No		105	40
11/22 load control injection	No		140	40
Switchyard	No	6	125	40
Ancillaries	No	6	80	40
Building	No	6	160	Wood 40 Brick 60

Table 5 Standard Asset Values For Power Transformers

Voltage	MVA	Unit Price $	Classification
33/11 kV	1.5	115,500	ONAN
	2.5	177,500	ONAN
	5	268,500	ONAN
	7.5	294,000	ONAN

	10	319,500	ONAN
	10/12.5	345,000	ONAN/ONAF
	15/20	421,000	ONAN/ONAF
	15/20/25	472,500	ONAN/ONAF/OFAF
	20/28/35	560,000	ONAN/ONAF/OFAF
66/11 kV	2.5	187,000	ONAN
	5	280,000	ONAN
	7.5	305,000	ONAN
	10	375,500	ONAN
	10/14	420,000	ONAN/ONAF
	15/20/25	507,500	ONAN/ONAF/OFAF
	20/28/35	607,500	ONAN/ONAF/OFAF
66/33/11 kV	7.5	360,000	ONAN
	15	700,000	ONAN
132/11 kV	15/20/25	638,000	ONAN/ONAF/OFAF
	35/40/45	858,000	ONAN/ONAF/OFAF
	50/60/65	1,025,000	ONAN/ONAF/OFAF
132/33 kV	20/30	717,500	ONAN/ONAF
	40/60	914,500	ONAN/ONAF
	60/120	1,456,500	ONAN/ONAF
132/66 kV	20/30	815,000	ONAN/ONAF
	30/60	1,025,000	ONAN/ONAF
	60/120	1.456,000	ONAN/ONAF