EnergyAustralia

EnergyAustralia's Submission to

Independent Pricing and Regulatory Tribunal

Design, Reliability & Performance Licence Conditions – Pass Through Application

1 December 2005

Energy

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1 Executive Summary

EnergyAustralia welcomes the new licence conditions

On 1 August 2005, the NSW Minister for Energy and Utilities ("the Minister") introduced new licence conditions on EnergyAustralia and the other NSW Distribution Network Service Providers (DNSP's) pursuant to clause 6(1)(b) of Schedule 2 of the Electricity Supply Act 1995, aimed at ensuring a more reliable supply of electricity to the residents of NSW.

EnergyAustralia welcomes the Minister's initiative to reflect the community's expectations of the quality and reliability of electricity supply that DNSP's are required to deliver into new licence conditions.

The improvements in security and reliability of supply reflected in the new licence conditions will require extensive works, which are incremental to those contemplated in IPART's *NSW Electricity Distribution Pricing 2004/05 to 2008/09 – Final Determination* (the Determination).

The focus of this application is to identify the additional programs required to meet the new licence conditions and to attain regulatory recognition of the associated costs.

Maintaining network stability

In 2004, IPART approved EnergyAustralia investing a record $2.1 billion in capital projects on its network and a further $1.5 billion on operating and maintenance expenditure to maintain the performance of the network.

EnergyAustralia's submission to IPART outlined its proposals on the capital investment needed to deliver different levels of performance on the electricity network. The submission clearly set out for IPART the three different cases for capital expenditure and the customer outcomes expected to be delivered for each.

IPART considered EnergyAustralia's detailed submission and accepted (with modifications) the "base case" scenario to maintain current performance on the electricity network. EnergyAustralia also submitted an "enhanced service levels" case, but this was not accepted.

The performance of our network has remained relatively stable, although as we outlined on our 2004 submission, some performance indicators are under pressure. However, we have generally maintained our performance despite undergoing rapid periods of growth to keep pace with development, meeting demand and replacing assets.

Meeting community expectations

The new licence conditions require a more prescriptive and "deterministic" approach to network management[1]. This is a material change from the "probabilistic" approach that underpinned EnergyAustralia's capital and asset management proposals that informed IPART's

[1] The new licence obligations contain a staged implementation to a fully deterministic regime by 1 July 2019. This application merely contains costs relating those requirements that must be met by 1 July 2009, and preparatory costs that are required in the current regulatory period to meet the 1 July 2012 standards.

Determination. The probabilistic approach resulted in substantially reduced capital expenditure requirements, and was consistent with the approach of maintaining existing service outcomes in line with the available regulatory funding.

The new licence conditions establish clear obligations for DNSPs regarding the design planning standards, minimum system reliability, security of supply, and performance outcomes to be delivered to customers.

Of particular relevance to EnergyAustralia's network is the fact that the licence conditions establish a governmental policy on the minimum design planning standards that will apply within the CBD and urban network areas. The licence conditions also seek to reduce differential service outcomes between customers through mandating improvements in the service delivered by the worst performing feeders and introduce guaranteed payments to customers that receive service outcomes below prescribed minimum levels.

The implementation of the new licence conditions by EnergyAustralia involves significant upfront investment in new and upgraded assets and operating programs. The majority of these costs relate to assets with lives spanning many decades.

Application for pass through

This submission represents EnergyAustralia's application to IPART for the "pass through" of the incremental costs to EnergyAustralia arising from the new licence conditions, in accordance with the procedures outlined in the Determination, and includes an application for:

- A **General Pass Through Event** resulting from an eligible Regulatory Change Event being the imposition of minimum design and reliability licence conditions; and
- A **Specific Pass Through Event** resulting from the imposition of Guaranteed Customer Service Standards (GCSS).[2]

The new licence conditions require:

- Significant improvements to average SAIDI and SAIFI – which will require targeted capital investments and increased operating expenditure to support additional response staff;
- Reporting of poor performing feeders against individual targets, analysis of the performance and, where appropriate, correction of the feeders within one year of the performance having been identified;
- That all new installations conform to the new design standards as of 1 July 2007, with all existing installations meeting the enhanced standards by 1 July 2009 – resulting in increased investment requirements in a number of asset classes to provide the prescribed system security and install the necessary contingent assets; and
- Payments to customers in the event of a failure to meet minimum customer service outcomes for that customer within a 12 month period – requiring system improvements

[2] The new licence conditions refer to "Customer Service Standards", which EnergyAustralia believes are in substance the Guaranteed Customer Service Standards referred to in the Determination. As a result the terms are used interchangeably in these applications for pass through.

to capture and manage greater data, increased billing and processing costs, and increased contact centre and claims staff numbers.

These requirements materially vary key parameters upon which the Determination was ultimately based to reflect Government policy and consumer expectations. Most notably:

- The network management approach underpinning the Determination is no longer an acceptable planning regime under the new licence conditions. As a result EnergyAustralia will need to increase capacity for redundancy within its network through significant network investments. The imposition of the licence conditions place an obligation on EnergyAustralia for such works to be brought forward to ensure compliance by 2009, and preparatory work to ensure compliance with increased design planning standards in the 2012 requirements, compared to the capital expenditure program submitted during the Determination process; and

- The licence conditions require EnergyAustralia to deliver service outcomes above those currently delivered, and those required and approved by the Determination. Indeed, the licence conditions require outcomes that exceed even those proposed by EnergyAustralia in its enhanced reliability capital expenditure proposal submitted to IPART during the Determination review process[3], and therefore require even greater levels of investments than have been estimated in the past.

EnergyAustralia is committed to meeting its obligations

EnergyAustralia supports the improvements to the framework that are created by the new obligations, and has commenced the process of establishing a long-term strategic response to the increased reliability requirements of the new licence conditions.

EnergyAustralia must maintain the current management system and make investments to build capacity to ensure compliance with the new average reliability standards and the development of increased response capacity within EnergyAustralia to manage both average and specific feeder reliability targets into the future.

To meet the mandatory reliability licence conditions set by the Minister, EnergyAustralia must not merely aim to achieve the standard, but to exceed it. This is driven primarily by the need to manage the statistical variation of random events that result in annual variations from the long-term trends in performance. EnergyAustralia has highlighted the issue of statistical variation in performance outcomes previously to IPART, most recently during the S-Factor discussions that formed part of the recent Determination process.

Review of the licence performance conditions

In his letter to EnergyAustralia the Minister also stated that:

> *I intend that these reliability performance conditions will be reviewed within two years to assess their effectiveness in facilitating the delivery of a reliable supply of electricity at reasonable cost.*

[3] The "enhanced" case was ultimately rejected by IPART in favour of EnergyAustralia's "base" case.

EnergyAustralia notes that the new licence conditions impose specific licence conditions on EnergyAustralia that we submit are eligible for "pass through" under the conditions set out in the Determination, and for which we are seeking the full recovery in this application. Should the aforementioned review of the performance conditions result in subsequent changes to EnergyAustralia's legislative obligations, EnergyAustralia will abide by its obligation to prepare a pass through application for the associated cost changes (either positive or negative) in accordance with the Determination at that time.

Summary of the pass through costs

In this application, EnergyAustralia is seeking approval from IPART to pass through the costs of the investment necessary to meet the new design planning and reliability licence conditions, as summarised in the following table.

Table 1: Summary of the "General Pass Through" Costs Sought[4]

Program	Capital Costs ($M)[5]	Operating Costs ($M)
Network Planning	534.1	23.3
Average and Individual Feeder Reliability	74.6	23.6
Total	**$608.7 million**	**$46.9 million**

In addition EnergyAustralia is seeking a specific pass through of the costs arising from compliance with the GCSS licence conditions. The total incremental capital and operating costs sought is $15.6 million.

While every effort has been made to derive the above forecast costs through comprehensive analyses, it should be noted that the level of detail available has been constrained as a result of the timing of the pass through application specified in the Determination.

Therefore EnergyAustralia hopes that it will have the opportunity to provide IPART and its technical consultant with any reasonable information requests that either may have to facilitate a timely assessment of this application.

Adjustment mechanism

EnergyAustralia notes that there are forecasting difficulties associated with assessing the costs to comply with the new licence conditions in light of many exogenous factors. This is aggravated by the fact that the pass through rules in the Determination provide for a "one-time-only" application by the DNSP within 90 days of the Positive Change Event/Specific Pass Through Event occurring. To attempt to address the impact of exogenous factors, and to avoid any perception of regulatory "gaming" that may arise regarding the costs included in this pass through application, EnergyAustralia advocates the introduction of an "adjustment mechanism".

[4] **Note:** The tables in this document may not add due to rounding from the underlying pricing model.
[5] **Note:** All costs are presented in real 2005/06 dollar terms.

We believe it is possible to do this in a manner that would keep administrative costs and processes to a minimum in recognition of IPART's concerns on this topic that were raised during the Determination process.

The adoption of an "adjustment mechanism" could mitigate against the risk of the actual costs to comply with the new licence obligations being materially different than the *ex ante* pass through amount allowed by IPART, while at the same time not impacting on any efficiency incentives that may have been intended by IPART in the establishment of the pass through mechanism.

EnergyAustralia looks forward to the opportunity to work with IPART to develop how such an "adjustment mechanism" within the constructs of the Determination could be established to assist IPART in ensuring that only the actual costs of complying with the new licence obligations, or the costs that are likely to incur, are passed through to customers.

A 1 July 2006 price change

EnergyAustralia appreciates that the timing of the introduction of the licence conditions, and the resulting pass through applications, creates administrative challenges for IPART to assess the applications in sufficient time for the pass through amount to be incorporated into prices from 1 July 2006. EnergyAustralia believes that it is in the public interest to ensure that the revenues required to fund the recognised costs are incorporated into prices as soon as practicable to enable a smooth transition. Therefore EnergyAustralia undertakes to provide IPART with all reasonable assistance to facilitate any approved pass through amounts being included in EnergyAustralia's 1 July 2006 Annual Pricing Proposal.

2. Introduction

2.1 Changed Circumstances

On 1 August 2005 the then Minister for Energy and Utilities (the Minister) introduced a series of new and enhanced obligations on the NSW Distribution Network Service Providers (DNSPs). The obligations require the DNSPs to meet increased standards in regards to design planning criteria, meet minimum reliability targets for individual feeders and feeders in aggregate, and enhanced Guaranteed Customer Service Standards (GCSS) with associated customer payments.

In a letter to EnergyAustralia discussing the setting of these new licence conditions, and recognising the risks to the DNSP's of a potential move to a national regulatory framework for distribution, the Minister stated that:

> *It is imperative that the NSW Government establishes a robust set of mandatory reliability standards for the [DNSP's] prior to any transfer of responsibility for network regulation to the Australian Energy Regulator.*

The new licence obligations were not provided for in IPART's *NSW Electricity Distribution Pricing 2004/05 to 2008/09 – Final Determination* (the Determination). However, IPART anticipated, and provided for, events that might occur within the regulatory period that sufficiently change the nature of the DNSPs' activities and costs, so as to trigger a pass through of these costs within the regulatory period.

EnergyAustralia has reviewed the nature of these changes and submits that the new licence conditions introduced by the Minister meet the requirements for two pass through applications under the Determination.

This submission sets out:

- EnergyAustralia's understanding of the new obligations;
- the manner in which the changes meet the criteria for two pass through applications under the Determination;
- the impact on EnergyAustralia's activities;
- the associated incremental costs of these changes; and
- the pass through amount being sought by EnergyAustralia.

2.2 Potential for Changes to the new Obligations

A review has been proposed to assess the effectiveness and the implementation of the licence conditions introduced by the Minister. This review is scheduled for completion by 1 August 2007. Recognising this review the Minister indicated in his covering letter to the licence conditions sent to EnergyAustralia that any recovery of costs should not include expenditures beyond the end of the current regulatory period, which is consistent with this application and indeed IPART's pass through rules.

However, EnergyAustralia will be required to commence works in the current regulatory period that are required to ensure that EnergyAustralia will be compliant with the new licence conditions in the next regulatory period, as a result of the planning, design and construction time to complete the relevant works. The costs of these projects have been included in EnergyAustralia's application to the extent that the costs are incurred in this regulatory period. The costs of these projects that will be incurred in the next regulatory period have not been included in the pass through costs sought in this application.

Whilst the review is an important aspect of ensuring the effectiveness of the introduced requirements, it does not in of itself require consideration beyond the cost horizon indicated above for the purposes of this submission. The reasons for this are two fold.

Firstly, EnergyAustralia is unable, and unwilling, to pre-empt the findings of the review, and any changes to the current obligations that may arise from the review. Further, any findings that modify the current obligations will not modify EnergyAustralia's obligations in the interim and EnergyAustralia is bound to comply with the current requirements until such time as the Minister changes these obligations.

Secondly, the pass through arrangements also provide for negative pass through events. Should the review change the obligations that form the basis of this submission in a material sense, then EnergyAustralia would submit an application at that time for a positive or negative pass through.

Accordingly, it should be assumed that IPART's pass through arrangements will facilitate full consideration of the current suite of new licence conditions and that any material changes to the obligations that may occur in the future are assessed as a separate matter at that time.

2.3 Pass Through Application Process

This is the first pass through application to be made under the Determination. Therefore, EnergyAustralia has, where possible, included the elements of the Determination and their references for the benefit of interested parties.

The Determination clearly establishes the processes and requirements relating to the application for, and assessment of, a pass through of costs. A key aspect of the requirements in the Determination is the minimum information that IPART has stated must be included in a pass through application. These information requirements are addressed in sections 5 and 6 of this application. EnergyAustralia requests that IPART's assessment be undertaken in sufficient time so as to allow the prices on 1 July 2006 to reflect the first year's pass through amount.

EnergyAustralia notes that whilst the Minister introduced new obligations on EnergyAustralia in a single document, the nature of these obligations will require two separate applications for pass through by virtue of clause 14.7 of the Determination. Given the common background to both applications EnergyAustralia has endeavoured to minimise the documentation required for consultation by combining both applications in this one document. However, it should be noted that the costs identified, pass through requested, and the proposed cost recovery for each application is separate.

3 Authority to seek Cost Pass Through

IPART included a general cost pass through mechanism and a specific cost pass through mechanism in its Determination. These mechanisms afford EnergyAustralia (and the other NSW DNSPs) the right to seek approval from the Tribunal for recovery of the costs incurred from pass through events.

3.1 Provisions for Pass Through of General Pass Through Events

Clause 14.1(a) of the Determination establishes EnergyAustralia's right to seek recovery of costs incurred as a result of a General Pass Through Event, as set out below

> *(a) If a DNSP reasonably considers that a Positive Change Event for that DNSP is likely to have occurred, the DNSP may seek the Tribunal's approval to pass through to Distribution Customers an amount (**Positive Pass Through Amount**) that is not greater than the Eligible Pass Through Amount (as calculated by the DNSP) in respect of that Positive Change Event.*[6]

The Determination defines a General Pass Through Event as being:

> *General Pass Through Event means a Regulatory Change Event or a Tax Change Event.*[7]

Relevantly:

> ***Regulatory Change Event** means:*
> *(1) a decision made by any Authority;*
> *(2) the coming into operation of an Applicable Regulation; or*
> *(3) the coming into operation of an amendment to an Applicable Regulation, on or after 1 July 2004 that:*
> *(4) has the effect of:*
> > *(i) imposing minimum standards on a DNSP in respect of the provision of Passthrough Distribution Services that are different from the minimum standards imposed on that DNSP in respect of the provision of Passthrough Distribution Services immediately prior to that event;*
> > *(ii) substantially altering the nature or scope of the services that, immediately prior to that event, collectively comprise the Passthrough Distribution Services; or*
> > *(iii) substantially varying the manner in which a DNSP is required to undertake any activity forming part of the Passthrough Distribution Services; and*
>
> *(5) results in a DNSP incurring Materially higher or Materially lower costs in providing Passthrough Distribution Services than it would have incurred but for that event,*
>
> *but does not include:*
>
> *(6) the making of this Determination;*
> *(7) a Tax Change Event; or*
> *(8) the imposition or removal of, or a change in (including a change in the application, official interpretation or manner of calculation of), any Demand Management Levy.*[8]

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[6] IPART, NSW Electricity Distribution Pricing 2004/05 to 2008/09 Final Determination, 2004, Page 24.
[7] IPART, NSW Electricity Distribution Pricing 2004/05 to 2008/09 Final Determination, 2004, Page 36.

Applicable Regulation includes any distribution network service provider's licence granted under the Electricity Supply Act 1995 (NSW).[9]

EnergyAustralia submits that the recent imposition of Design Reliability and Performance requirements as part of EnergyAustralia's licence conditions constitutes a Regulatory Change Event within the meaning of subclauses (3) and (4) of the above definition.

Furthermore, EnergyAustralia submits that this Regulatory Change Event satisfies the materiality threshold set out in subclause (5) of the definition[10]. That is, the imposition of new planning and reliability standards results in EnergyAustralia incurring "Materially higher" costs that exceed 1% of EnergyAustralia's average annual smoothed revenue requirement. Satisfaction of the materiality threshold is demonstrated below in section 6.3 of this application, "Meeting the Materiality Threshold for General Pass Through Events".

3.2 Provisions for Pass Through of Specific Pass Through Events

EnergyAustralia also has the right to seek the approval from the Tribunal to pass through costs incurred as a result of a Specific Pass Through Event pursuant to clause 15.1 of the Determination as follows:

*If a Specific Pass Through Event occurs, a DNSP may seek the Tribunal's approval to pass through to Distribution Customers an amount (**Specific Pass Through Amount**) that is not greater than the Eligible Pass Through Amount (as calculated by the DNSP) in respect of that Specific Pass Through Event for that DNSP.*[11]

The Determination defines a specific pass through event as being:

***Specific Pass Through Event** means any of the following events where they occur on or after 1 July 2004:*

(1) the coming into operation of, or of any changes to, any legislation of the Parliament of New South Wales, or any regulation, order, rule or other instrument made under such legislation, that has or have the effect of altering the requirements governing live-line working procedures;
(2) the coming into operation of any changes to the expression "electrical installation" as the expression is defined in the Electricity (Consumer Safety) Act 2004;
(3) the imposition of guaranteed customer service standards that are in addition to those that apply in respect of a DNSP as at 1 July 2004, any change to guaranteed customer service

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[8] IPART, NSW Electricity Distribution Pricing 2004/05 to 2008/09 Final Determination, 2004, Page 39 and 40.
[9] IPART, NSW Electricity Distribution Pricing 2004/05 to 2008/09 Final Determination, 2004, Page 32.
[10] See also, clause 2.2(a), Annexure 1, IPART, NSW Electricity Distribution Pricing 2004/05 to 2008/09 Final Determination, 2004, Page 44
[11] IPART, NSW Electricity Distribution Pricing 2004/05 to 2008/09 Final Determination, 2004, Page 29.

standards that apply in respect of a DNSP during the Regulatory Control Period, or any change in the magnitude of the expected payments that may be required to be made to Distribution Customers by a DNSP as a result of any such additional or changed guaranteed customer service standards; or
(4) the imposition of any mandatory requirement on DNSPs to replace existing meters used to measure the consumption of electricity by Distribution Customers with meters that measure the consumption of electricity at specific time intervals, commonly referred to as interval meters.[12]

EnergyAustralia is making this application for approval to pass through costs arising from the imposition of additional Guaranteed Customer Service Standards by the Minister as specified in clause (3) above. EnergyAustralia submits that this event has met the requirements specified by the Determination above for cost pass through.

Unlike a General Pass Through Event, there is no materiality threshold for a Specific Pass Through Event.

[12] IPART, NSW Electricity Distribution Pricing 2004/05 to 2008/09 Final Determination, 2004, Page 41.

4 IPART's Requirements

When making its Determination, IPART established a series of minimum information requirements that must be included in any pass through application, and the timing of any such application. These requirements are articulated in clauses 14.2(a) and 15.2(a) of the Determination and, whilst these two clauses reference the relevant defined terms for the general and specific pass through arrangements respectively, the core requirements are nonetheless the same.

IPART's information requirements for the application are set out in the table below with the corresponding sections of this application to those requirements.

Table 3: Information to be addressed in the application

IPART's Information Requirements	Reference for this Application
The details of the Event concerned.	Section 5.1 – Details of the Pass Through Event
The date the relevant Event occurred.	Section 5.2 – The Pass Through Event Date
The increase in costs in the provision of Pass Through Distribution Services that the DNSP has incurred since 1 July 2004 and is likely to incur until the end of the Regulatory Control Period as a result of the relevant Event [ie the Eligible Pass Through Amount (as calculated by the DNSP) in respect of that Event].	Section 6.1 – Summary of the Costs that will be incurred prior to 30 June 2009
The Pass Through Amount the DNSP proposes in relation to the Event.	Sections 6.1.3 and 6.1.4 – Total Pass Through Amount for General Pass Through Events and GCSS Licence Conditions
The amount of that Pass Through Amount that the DNSP proposes should be passed through to Distribution Customers in each Year during the Regulatory Control Period.	Section 6.1.5 – Total Pass Through Amount Sought for all Pass Through Events
Evidence of the actual and likely increase in costs – Planning and Reliability requirements	Sections 6.3 to 6.5 – Average and Individual Reliability Program Cost Details and Design Planning Program Cost Details
Evidence of the actual and likely increase in costs – GCSS requirements	Section 6.6 – GCSS Program Cost Details
Evidence that the costs occur solely as a consequence of the Positive Change Event.	Sections 6.3 to 6.5 – Average and Individual Reliability Program Cost Details and Design Planning Program Cost Details
Evidence that the costs occur solely as a consequence of the Specific Pass Through Event.	Section 6.6 – GCSS Program Cost Details

5 Background to the Pass Through Event

5.1 Details of the Pass Through Event

Pursuant to item 6(1)(b) of Schedule 2 of the Electricity Supply Act 1995, the Minister of Energy and Utilities introduced new licence conditions on the NSW DNSPs on 1 August 2005.

In his covering letter to EnergyAustralia attached to the new licence conditions, the Minister stated that:

> *It is imperative that the NSW Government establishes a robust set of mandatory reliability standards for the [DNSP's] prior to any transfer of responsibility for network regulation to the Australian Energy Regulator.*

Further, the Minister stated that:

> *I intend that these reliability performance conditions will be reviewed within two years to assess their effectiveness in facilitating the delivery of a reliable supply of electricity at reasonable cost.*

The licence conditions relate to, and impact on, four key operational and network management areas:

- Design planning criteria, including system redundancy requirements;
- Reliability standards (targets for average SAIDI and SAIFI);
- Minimum individual feeder performance; and
- Guaranteed Customer Service Standards

The prescription of these matters removes a significant level of discretion and risk management options that underpinned EnergyAustralia's probabilistic capital and operating programs proposed during the 2004 Distribution Pricing Review. The probabilistic approach had made it possible for EnergyAustralia to minimise the size of the capital program and therefore keep prices to customers at a minimum. A copy of the licence conditions is attached as Attachment 1.

5.2 The Pass Through Event Date

EnergyAustralia submits that both the General Pass Through Event and the Specific Pass Through Event occurred on 1 August 2005, being the date that the new licence conditions were introduced by the Minister.

The imposition of the design and reliability licence conditions constitutes a "Regulatory Change Event" being the "coming into operation" of an amendment to EnergyAustralia's network service provider's licence. The conditions were introduced on 1 August 2005 by the Minister and, except where expressly stated otherwise, take effect from that date. Accordingly, the relevant event occurred on 1 August 2005.

The GCSS obligations constitute a Specific Pass Through Event being the "imposition of guaranteed customer service standards that are in addition to those that apply in respect of a DNSP as at 1 July 2004". EnergyAustralia submits that the relevant Specific Pass Through

Event occurred on the date of imposition of the GCSS obligations even if those provisions do not come into effect until a later date.

5.3 Timing of the Pass Through Application

Pursuant to clauses 14.2(a) and 15.2(a) of the Determination, EnergyAustralia must make an application to IPART for approval of the pass through amount on or before 5 December 2005, being 90 working days after the relevant pass through events occurred. EnergyAustralia therefore submits that these applications meet IPART's timing criteria.

This clearly demonstrates that EnergyAustralia has taken positive steps by submitting this application early, to ensure that IPART has sufficient time to undertake its review and notify EnergyAustralia of the price change to be effective as of 1 July 2006.

6 Costs Incurred or Forecast to be Incurred by 30 June 2009

The costs submitted in this application to IPART consist of the:

- Direct incremental capital expenditure;
- Direct incremental operating expenditure; and
- Operating expenditure increases arising from increased numbers of assets to maintain and operate.

The methodologies applied to the develop the direct capital and operating expenditure forecasts are discussed below in relation to the relevant compliance programs, as they are specific to that program.

With respect to operating expenditure costs incurred due to increased assets, the methodology applied is an extrapolation of the underlying approach accepted for, and applied in, the Determination.

EnergyAustralia used the allowed operating expenditures from the Determination and rolled forward replacement cost for the regulatory asset base to determine the operating cost to replacement cost ratio for each year of the regulatory period. The resulting relationship between the operating expenditures and the replacement costs of assets was calculated to be 2.62% on average for the remaining years of the regulatory period. This percentage has been applied annually to the replacement cost of the cumulative incremental capital expenditure in each financial year that expenditure occurs.

In estimating the incremental costs attributable to the licence compliance requirements, for Sub-transmission Lines, Sub-transmission Substations and Zone Substations, EnergyAustralia has determined the loading and, where applicable, the load at risk based on the most recent forecast and rating data applicable to each individual network element. Where the compliance requirements are deterministic or where load at risk is expected to exceed 1% during (or shortly after) the period ending 30 June 2009, an assessment has been made of the most cost effective means of addressing the licence compliance requirements.

In some cases this has been achieved by transferring loads to adjacent substations, or by the installation of additional transformer capacity. In a small number of cases it will be necessary to bring forward the construction of new substations and the associated Sub-transmission Lines. The costs associated with projects that have received funding under the earlier IPART Determination and those regulated as transmission assets have been removed from this application.

EnergyAustralia has used a coincident probability calculation for a number of years. We calculate the probability of an equipment failure occurring in one or both of the peak seasons of summer and winter, at the same time that the load on the zone substation exceeds its firm rating. Each peak season is considered to be four months long.

The coincidence probability calculation is relatively complex and incorporates a number of factors such as standard equipment repair times and lengths of sub-transmission feeders. Standard average equipment failure rates are used.

The basic principle used combines the percentage of time in the four month peak season that the load will be over the substation firm rating, with the probability of failure of any one item of key equipment (zone transformers and sub-transmission feeders) in the peak season. The analysis is split into two peak seasons because different ratings apply and to keep data manipulation times at a reasonable level.

The methodology needs to be applied carefully, to screen out spurious SCADA load spikes, and with the understanding that it loses accuracy for highly loaded substations (over 5% risk) or for substations with very flat load profiles.

Illustration 1: Calculation of 1% load at risk

> If the substation load exceeds firm rating in the peak season for a total of 39 hours, and the seasonal equipment failure rate is 0.8, then:
>
> Coincident probability (%) = (39 hours / (24 hours x 122 days)) x 0.8 x 100
> = 1.07 %

If the seasonal coincident probability is greater than 1% in either peak season, the zone is considered to exceed the 1% risk criterion.

EnergyAustralia has examined its extensive pool of 11kV feeders, and assessed how many of those feeders are required to be compliant with the design planing requirement of N-1 capability within a 4-hour switching window. In the time available to prepare this application, it has not been possible to individually assess and develop a remediation plan for each individual feeder, however EnergyAustralia is confident that its statistical methodology is sufficiently robust to provide reasonable cost estimates.

In assessing the probable costs associated with this obligation, EnergyAustralia has, as a starting point, assumed that four hours is sufficient time for only four switching steps. This constraint leads to the adoption of a “5 into 4” planning concept.

Applying a “5 into 4” planning concept means that if one feeder fails, its load can be manually switched to 4 adjoining feeders ensuring that the loss of an entire feeder does not result in significant loss of supply to customers. In order to achieve this, maximum feeder loading needs to be restricted to 80% of the feeder rating, and interconnections need to be created between feeders. By capping the feeder utilisation to 80% of its capacity, each feeder will have sufficient **capacity** to bear 25% of the load supplied by an adjoining feeder, and still operate well within the operational capacity of the feeder.

Currently EnergyAustralia has in the order of 360 feeders that are being utilised at more than 80% of its capacity, and that number is expected to increase by 30 feeders annually. It should be noted however, that these feeders are currently being operated within their individual utilisation tolerances, which simply means that each of these feeders may not have sufficient

available capacity to bear the full 25% of neighbouring feeder's loads required to meet the "5 into 4" planning concept.

EnergyAustralia has recently completed a series of projects to reduce loading (albeit at a higher level) on a number of 11kV feeders. An assessment of the "average cost per feeder relieved" has been made based on the detailed estimates associated with these individual projects, and this cost has been applied to the number of feeders with current loading in excess of 80% of rating. Funding previously approved by IPART on related programs has been deducted from the aggregate amount claimed in this application.

This approach may understate the eventual cost of this project, as projects to date have generally utilised spare 11kV circuit breaker panels in Zone Substations when installing new feeders. However, there are a limited number of such panels available and this approach may not be possible for all future works. Future projects may require different solutions, such as connecting two feeders onto one panel of switchgear. This in itself will also necessitate increased distribution automation to ensure appropriate reliability levels on each feeder. Nevertheless, EnergyAustralia believes the current estimate of the cost of this compliance requirement is the best available.

The criteria contained in Schedule 1 of the licence conditions require a range of responses by EnergyAustralia to ensure compliance across the range of obligations. However, for approximately half of the requirements EnergyAustralia does not anticipate any incremental expenditure over the current regulatory period.

To meet the mandatory reliability licence conditions set by the Minister, EnergyAustralia must not merely aim to achieve the standard, but to exceed it. This is driven by both the need to manage the statistical variation of random events that result in annual variations from the long-term trends in performance and EnergyAustralia's expectations that reported performance will deteriorate with the implementation of the Outage Management System due to improved available data. To simply aim to achieve the standard would mean that based on simple statistics, EnergyAustralia would breach its licence conditions approximately every second year. EnergyAustralia has highlighted the issue of statistical variation in performance outcomes previously to IPART, most recently during the S-Factor discussions that formed part of the recent Determination process.

To determine the level of capital and operational expenditure required to meet Schedule 2 "(Average) Reliability Standards" and Schedule 3 "Individual Feeder Standards", EnergyAustralia has examined the performance of individual feeders in detail. Based on the length and number of feeders not meeting the individual standard, we have assessed the length of line that will require detailed inspection and remediation work. Furthermore, we have assessed the likely number of tasks that will arise from this program, and applied unit cost estimates to determine the total cost.

The impact of the individual feeder program on the average reliability of each feeder category has been assessed, and the need to implement additional works to ensure compliance with average feeder standards has been identified based on the statistical distribution of reliability data, historical performance and the planned individual standard program. In the case of Short

Rural and Long Rural Lines, additional programs will be required. To accommodate this, the individual feeder program has been extended.

6.1 Summary of Incremental Costs that will be Incurred by 30 June 2009

The criteria contained in Schedule 1 of the licence conditions require a range of responses by EnergyAustralia to ensure compliance across the range of obligations. However, for approximately half of the requirements EnergyAustralia does not anticipate any incremental expenditure over the current regulatory period. The summary of EnergyAustralia's forecast capital expenditure programs against each of the criteria contained in Schedule 1 of the licence conditions is set out in section 6.1.1 below.

6.1.1 Pass Through Amount for the Design Planning Licence Conditions

The design planning standards establish the degree of redundancy or backup systems that must be in place for the major categories of assets that operate within each of the defined supply areas: CBD, urban and rural. The table below lists the design planning requirements set out in Schedule 1 of the licence conditions and EnergyAustralia's forecast capital and operating program costs required to ensure compliance with each requirement.

Table 4: Design Planning Criteria Compliance Program Cost Summary (Schedule 1)*

Design Planning Requirement	Capital Expenditure ($M)	Operating Expenditure ($M)
N-2 Criteria Sydney CBD Sub Transmission Lines	44.42	1.73
N-2 Criteria Sydney CBD Zone Substations	56.18	2.34
N-2 Criteria CBD Sub-Transmission Substations	0	0
N-1 Criteria Sub Transmission Lines	27.5	1.17
N-1 Criteria Urban and Non-Urban Sub Transmission Substation	0	0
N-1 Criteria Urban and Non-Urban Zone Substations	126.44	5.52
N-1 Criteria CBD Distribution Feeders	0	0
N-1 Criteria Urban Distribution Feeders	279.03	12.51
N-1 Criteria CBD Distribution Substations	0	0
N Criteria Non-Urban CBD Sub Transmission Lines	0	0
N Criteria Non-Urban Zone Substations	$0.52	0.02
N Criteria Urban Distribution Feeders (for urban areas with <15,000 customers)	0	0
N Criteria Non-Urban Distribution Feeders	0	0
N Criteria Urban and Non-Urban Distribution Substations	0	0
Total	**$534.09 million**	**$23.28 million**

* Note: All costs presented in this submission are in real 2005/06 dollar terms unless otherwise stated.

6.1.2 Pass Through Amount for the Network Reliability Licence Conditions

EnergyAustralia will be primarily focusing its reliability programs on meeting the individual feeder reliability requirements contained in Schedule 3 of the licence conditions. It is expected that the individual feeder program will enable EnergyAustralia to meet the average reliability targets for feeder classes contained in Schedule 2 of the licence conditions with the inclusion of minor risk mitigation works designed to limit cascading faults and damage. The costs for these two programs are set out in the tables below.

Table 5: Average Feeder Reliability Compliance Program Cost Summary (Schedule 2)

Program	Capital Expenditure ($M)	Operating Expenditure $(M)
Risk Mitigation	2.07	0.09
Average feeder reliability[13]	0	0
Total	**$2.07 million**	**$0.09 million**

Table 6: Individual Feeder Reliability Compliance Program Cost Summary (Schedule 3)

Program	Capital Expenditure ($M)	Operating Expenditure $(M)
Feeder Inspection and Thermovision Program	4.60	14.72
Distribution Automation Program	27.62	1.15
Wildlife Proofing Program	0	2.57
Protection and Communication Program	14.72	0.44
Conductor Program	25.22	1.03
Mobile Generators and Distribution Substation Program	0.41	3.58
Total	**$72.57 million**	**$23.49 million**

6.1.3 Total Pass Through Amount for the General Pass Through Events

The total costs arising from the licence conditions that are being claimed through the general pass through event clauses of the Determination are summarised below.

Table 7: Total Planning & Reliability Compliance Cost Summary (Schedules 1 – 3)

Program	Capital Expenditure ($M)	Operating Expenditure $(M)
Design Planning	534.09	23.28
Average feeder reliability	2.07	0.09
Individual feeder reliability	72.57	23.49
Total	**$608.73 million**	**$46.86 million**

[13] Feeder works for average reliability have been included in the individual reliability programs where appropriate to avoid potential for double counting of projects between purposes.

EnergyAustralia proposes to pass through in full the eligible pass through amount, as defined by the Determination, being the incremental costs incurred, and likely to be incurred, between 1 July 2004 and 30 June 2009 arising from the planning and reliability licence conditions as contained in Attachment 1.

EnergyAustralia forecasts that the incremental costs that will be incurred by 30 June 2009 relating to the new design planning and reliability licence conditions will be $608.73 million of capital expenditure and $46.86 million of operating expenditure, resulting in a total expenditure of $655.51 million (in $2005/06).

6.1.4 Pass Through Amount for the GCSS Licence Conditions

The forecast costs for the GCSS licence conditions are set out below, and illustrate the impact on payments to customers resulting from the tightening of the requirements in the 2008/09 financial year. As shown in section 6.6, these costs are primarily the result of processing and paying claims for poor performance under the GCSS provisions of the licence conditions. The costs set out below represent the total costs being claimed via the specific pass through provisions of the Determination.

Table 8: GCSS Compliance Program Cost Summary

Program	Capital Expenditure ($M)	Operating Expenditure $(M)
Development (pre 1 July 2006)	0.08	0.43
Annual Costs – 2006/07	0	4.50
Annual Costs – 2007/08	0	4.46
Annual Costs – 2008/09	0	6.09
Total	**$0.08 million**	**$15.47 million**

EnergyAustralia proposes to pass through the full eligible pass through amount, as defined by the Determination, being the incremental costs incurred, and likely to be incurred, between 1 July 2004 and 30 June 2009 arising from the GCSS licence conditions as contained in Attachment 1.

EnergyAustralia's forecast costs for implementing the GCSS licence conditions is $9.08 million of capital expenditure and $15.47 million of operating expenditure. However, included in the capital expenditure costs of $9.082 million is the cost estimate for the development of an outage management system totalling $9 million. As IPART provided for this cost in the Determination, the incremental capital expenditure for which EnergyAustralia is seeking to pass through is $82,400.

Therefore, the eligible pass through amount being sought is $0.08 million of capital expenditure and $15.47 million of operating expenditure, resulting in a total pass though amount of $15.55

million. These costs are summarised in Table 9 above, with the detailed programs discussed in section 6.6 below.

6.1.5 Total Pass Through Amount Sought for all Pass Through Events

The total pass through costs that are being sought by EnergyAustralia for both the general and specific pass through events is $617.43 million in capital expenditure costs and $62.84 million in operating expenditure costs.

Table 9: Total Pass Through Amounts Sought for all Pass Through Events

Program	Capital Costs ($M)	Operating Costs ($M)
General Pass Through Costs	608.73	46.86
Specific Pass Through Costs	0.08	15.47
Total	**$608.81 million**	**62.33 million**

6.2 Meeting the Materiality Threshold for General Pass Through Events

For an event to meet the definition of a General Pass Through Event it must, amongst other things, be material. The materiality threshold established by IPART is based on the average annual cost impact over the remainder of the regulatory period. The threshold set by IPART for a General pass Through Event in clause 2.2 of Annexure 1 of the Determination is if "*the annual average change in costs in respect of that event exceeds 1% of the average annual smoothed revenue requirement for the DNSP*". For EnergyAustralia, one per cent of the average annual revenues has been deemed by IPART to be $8.244 million as per Annexure 12 of the Determination.

To establish whether the costs incurred by EnergyAustralia meet IPART's hurdle requirement the following formula has been used, as derived from clause 2.2(a) of Annexure 1 of the Determination:

A = X/(Y/12)

where: A = the average annual change in costs;

X = the total net costs incurred or saved as a result of the event for the regulatory period; and

Y = the number of whole months between the date the pass through event occurred and 30 June 2009.[14]

To determine A, the following data was used.

*X = $655.59 million*15

Y = 46 months[16]

[14] IPART, NSW Electricity Distribution Pricing 2004/05 to 2008/09 Final Determination, 2004, Page 44.
[15] From Table 9 above.

Therefore the average annual change in costs for this event is $171.02 as calculated below:

A = X/(Y/12);

A = $655.59 / (46/12); therefore

A = $171.02 million

When the average annual change in costs of $171.02 million is compared to the materiality hurdle of $8.244 million it is clear that this event exceeds the materiality threshold set by IPART in the Determination.

6.3 Design Planning Criteria Program Cost Details (Schedule 1)

The new licence obligations impose the implementation of deterministic planning criteria for all areas of EnergyAustralia's distribution network by 2019. This is broken into several stages with aspects of the network required to meet various standards by 2009, 2012 and finally full implementation by 2019. This application for pass through incorporates those requirements that must be met by 1 July 2009, and preparatory work that is required to be undertaken in this regulatory period to ensure compliance with the obligations that take effect as of 1 July 2012. The 2019 requirements have not been considered in this application.

6.3.1 Summary of the Design Planning Forecasting Methodology

EnergyAustralia has examined all classes of assets and their geographical locations and network usage against the EnergyAustralia's understanding of the requirements of Schedule 1 of the new licence conditions. Notably, in developing the forecast program to ensure compliance with the new licence conditions EnergyAustralia was required to develop a view as to the interpretation of the Sydney CBD N-2 with 1% load at risk criterion.

Therefore, EnergyAustralia has interpreted and applied the N-2 with 1% load at risk in the following manner:

1. Credible N-2 scenarios were developed and contingencies assessed for those assets governed by the N-2, 1% load at risk criteria.
2. Based on these contingencies the probability of a secondary event occurring prior to the primary event being rectified, and that would result in load shedding, is less than 1%.

This measure is purely a measure of probability of load shedding, i.e. load being at risk, and does not attempt to measure the volume of load that would be at risk from a binding N-2 event that would statistically occur (at most) in one out of every 100 years. Whilst EnergyAustralia does not believe it has any assets that breach the N-2, 1% criteria, it is required to prepare for the implementation of deterministic N-2 by 2012. Considering the substantial lead times for CBD augmentations, EnergyAustralia has been required to plan to commence programs in this regulatory period to meet this licence condition. This approach was similarly applied to the N-1,

[16] August 2005 has been disregarded as it is not a full month from the introduction of the new obligations

1% load at risk criteria and the required target of full compliance with the limit of 1% load at risk by 2009.

The conversion of the licence conditions into specific programs of work required significant statistical, probabilistic and engineering analysis. Evans and Peck have independently reviewed EnergyAustralia's data and the resulting analysis. The report is included as Attachment 2 to this application.

6.3.2 N-2 Criteria Sydney CBD Sub-Transmission Lines

EnergyAustralia's policy at the time of the Determination was to achieve "N-1" redundancy in zone substations in the CBD. Schedule 1 of the licence requirements requires a redundancy level of "N-2" in new CBD zone substations and sub-transmission lines commissioned after 1 July 2007, and for all CBD zone substations and sub- transmission lines from 1 July 2009 (subject to an allowance for a 1% loss of load probability until 30 June 2012).

At the time of the Determination EnergyAustralia had planned to develop the City North zone substation as a 4 transformer, N-1 substation. It is scheduled for completion in late 2009. The new licence condition necessitates the installation of an additional sub-transmission line to supply a 5th transformer at City North in order to achieve "N-2".

The information in the table below highlights that $15.2 million[17] was included in the Determination for feeder construction works associated with the City North CBD zone substation. These costs were based on the need to connect four sub-transmission feeders to the zone substation via ducts.

However, the introduction of the new licence condition requires that EnergyAustralia increase the number of transformers at City North from 4 to 5 to meet the "N-2" criteria. This is a substantial change in the design of the substation and the additional feeder required to service City North is of particular concern. EnergyAustralia will now be required to build a tunnel to accommodate the five feeders, as compared to the duct option that was available for four feeders.

The costs being sought to be passed through are the incremental costs of the tunnel versus the duct option and those of the 5th feeder itself. Following the details below, and recognising the requirement for an extra transformer and therefore an extra feeder into City North, EnergyAustralia submits that the costs sought are incremental to those provided for in the Determination.

[17] In 2003/04 dollar terms. This equates to $16.2 million in 2005/06 dollar terms.

Table 10: N-2 Criteria Sydney CBD Sub-Transmission Line Program Cost Summary

Program	2005/06	2006/07	2007/08	2008/09
Capital expenditure ($M)	0.9	17.44	24.24	18.04
Capex in the Determination ($M)	0.9	5.50	4.31	5.50
Incremental Capex ($M)	0.0	11.95	19.93	12.54
Operating expenditure ($M)	0	0.16	0.57	1.00
Total Costs ($M)				**$46.15 million**

6.3.3 N-2 Criteria Sydney CBD Zone Substations

As outlined in 6.3.2 above, EnergyAustralia is required to install a 5th transformer at City North zone substation in order to comply with the requirement for "N-2" redundancy in CBD zone substations. This will necessitate some changes to building design, an additional transformer and associated cabling, protection and control.

In addition to City North, there are four other zone substations in the CBD that are generally built to an "N-1" redundancy standard. It is impractical to install additional transformers in Dalley St, City Central or City South. This will necessitate the development of new capacity at one or more other locations, with increased 11kV interconnection between these substations to provide an equivalent "N-2" redundancy.

Whilst there is a long-term plan to redevelop City East, those plans currently do not require expenditure in the period covered by the current Determination. The need to meet "N-2" redundancy, notionally by 2009 but absolutely by 2012, necessitates advancement of some work including land acquisition, design, initial construction and 11kV feeder augmentation into the 2005/6 to 2008/9 period.

The current estimate of required capital expenditure on these projects is:

Table 11: N-2 Criteria Sydney CBD Zone Substation Program Cost Summary

Program	2005/06	2006/07	2007/08	2008/09
Capital expenditure ($M)	0	24.17	12.69	19.31
Capex in the Determination ($M)	0	0	0	0
Incremental Capex ($M)	0	24.17	12.69	19.31
Operating expenditure ($M)	0	0.32	0.80	1.22
Total Costs ($M)				**$58.52 million**

6.3.4 N-2 Criteria CBD Sub-Transmission Substations

The replacement City East will be a 132kV / 11kV substation (the existing substation is 33kV/ 11kV). The associated 132kV sub-transmission lines will emanate from Surry Hills sub-transmission substation. As a result of the City East replacement, associated design and development works are required at the Surry Hills sub-transmission substation in the 2005/6 to 2008/9 period. This is considered a transmission project and therefore EnergyAustralia will be seeking pass through from the AER in due course.

6.3.5 N-1 Criteria Sub-Transmission Lines

Schedule 1 of the new licence conditions – Design Planning Criteria requires that all urban and non-urban sub-transmission lines with loads greater than 5 MVA must meet deterministic “N-1” security standard by 1 July 2009. The criteria do not make provision for load at risk.

EnergyAustralia’s stated planning preference for sub-transmission lines is that "for network loads above 5MVA .... are generally planned using a deterministic (n-1) criteria"[18]. However, EnergyAustralia is required to manage and prioritise its capital projects within the economic constraints of its regulatory determinations. In particular it was recognised, and indeed a core assumption, in the Determination that EnergyAustralia’s network would need to be managed utilising risk based criteria rather than deterministic criteria.

In its role as network manager and operator under the economic determinations EnergyAustralia must make investment decisions that balance the economic and service outcomes within reasonable risk tolerances. Although EnergyAustralia has clearly articulated its preferred standard of a deterministic N-1, the standard implemented for each particular project will reflect EnergyAustralia’s assessment of the relative risks and costs associated with the various design planning standards.

However, the new licence conditions remove management discretion regarding this balance and obligate EnergyAustralia to meet minimum planning requirements. Therefore, despite EnergyAustralia having started a clear preference for the N-1 standard it is now bound to apply the standard for ALL projects in this category, which was not the case previously.

Therefore, the imposition of the N-1 planning standard and the need to provide support to zone substation augmentations under the new licence conditions require EnergyAustralia to undertake several investments that it would not have otherwise undertaken within the economic confines of the Determination.

Section 6.3.7 below outlines 18 zone substation projects in the Sydney region that now require work in the 2005/6 to 2008/9 period as a result of the licence compliance conditions. In some cases, additional transformers are required. The combination of the N-1 requirement on sub-transmission lines, and the zone substation work necessitates 4 additional sub-transmission line projects in the Sydney region. These are:

- Vales Pt - Lake Munmorah 132kV
- Munmorah - Lake Munmorah 132kV

[18] EnergyAustralia, Network Management Plan

- Erina - Avoca 66kV
- Hunters Hill 90J 132kV

Three of these feeders – Vales Point to Lake Munmorah, Lake Munmorah to Munmorah and Hunters Hill 90J are regulated as transmission assets, and therefore the cost of this work has not been included in this submission.

EnergyAustralia has also reviewed the forecast loadings on all sub-transmission lines in the Hunter region, and determined their utilisation in comparison to their design rating, as outlined in section 6.3.7 below. A number of sub-transmission lines in the Hunter are forecast to exceed their design rating in the event of an outage on a related feeder – that is, they do not meet N-1. As a consequence, capital expenditure is required on 7 sub-transmission lines:

- Glebe - Merewether 960 132kV
- Glebe - Merewether 961 132kV
- Newcastle - Beresfield 9NA 132kV Upgrade
- Tomago - Williamtown 10 33kV
- Tomago - Williamtown 7 33kV
- Denman - Merriwa 33kV Upgrades
- Kurri to Cessnock 33kV

One of these feeders – the Newcastle to Beresfield feeder – is a regulated transmission asset and therefore its cost has not been included in this submission. The additional capital expenditure sought for the distribution projects is set out in the table below.

Table 12: N-1 Criteria Sub-Transmission Line Program Cost Summary

Program	**2005/06**	**2006/07**	**2007/08**	**2008/09**
Capital expenditure ($M)	1.00	6.80	14.22	5.48
Capex in the Determination ($M)	0	0	0	0
Incremental Capex ($M)	1.00	6.80	14.22	5.48
Operating expenditure ($M)	0.01	0.12	0.39	0.65
Total Costs ($M)				**$28.67 million**

6.3.6 N-1 Criteria Urban and Non Urban Sub-transmission substations

Schedule 1 of the new licence conditions – Design Planning Criteria requires that Urban and Non Urban sub-transmission substations meet an N-1 risk criterion by July 2009. EnergyAustralia considers that the Kurri sub-transmission substation will require reconstruction to meet this standard. However, it is regulated as a transmission asset and the associated cost has therefore not been included in this submission.

6.3.7 N-1 Criteria Urban Zone Substations

Schedule 1 of the new licence conditions – Design Planning Criteria – requires that all urban and non-urban zone substations with load in excess of 5MVA notionally meet the deterministic N-1 criteria by 1 July 2009. However, an allowance has been made to permit up to 1% load at risk per annum for the foreseeable future. Following the release of the licence compliance conditions, and as outlined in 6.3.5 above, EnergyAustralia has reviewed and calculated the forecast load at risk on all zone substations.

As a result of this review, 18 zone substations in Sydney and 7 zone substations in the Hunter region have been identified as being non-compliant by 2009 or shortly thereafter, based on the 2004/05 summer forecasts and/or the 2004 winter forecasts. In particular EnergyAustralia has included preparatory work to ensure that substations that would be non-compliant in the 2009/2010 summer period, i.e. 6 months into the next regulatory period, have sufficient work undertaken in this regulatory period to enable compliance early in the next regulatory period.

In EnergyAustralia's submission to the 2004 determination, based on the peak demand forecasts at the time and, combined with a number of proposed capital expenditure programs, a likely 2009 scenario was provided. In the base case scenario (accepted with modifications by IPART) this envisaged that despite the significant program, 10 substations would still be operating in excess of EnergyAustralia's peak demand criteria of 117% of firm rating. This would see a continuation of the probabilistic approach adopted both for the previous period and during the current period (eg in 2004 the number of substations operating in excess of firm rating stood at 29, which then increased marginally over the period before reducing back to 10).

IPART at the time adopted (and modified) the base case despite the exceedance of EnergyAustralia's nominal planning criteria.

Accordingly since the determination EnergyAustralia has actioned the approved capital program and annually revised its spatial forecasts and risk calculations. The latest revision based on Summer 2004/05 whilst at a global level being largely in line with forecast sees significant spatial variation from that used for the Determination. Whilst the variance in spatial demand is a risk that is borne by EnergyAustralia under the Determination, EnergyAustralia is now required to fully apply a maximum 1% load risk criterion for requiring capital expenditure. Whilst it is generally consistent in outcomes to EnergyAustralia’s use of the 117% of firm rating trigger used for the recent distribution review, it is not the same in all cases.

This is because the 1% risk assessment considers the time over which an asset is running beyond firm capacity in addition to the level of exceedance over the firm rating. The 117% of firm rating focused more on the magnitude of peak demand over firm rating and less on the time at which the asset was over firm rating. In this way an asset that could have been forecast to exceed its firm rating, but not reaching 117%, could in fact have an equal, or greater, probability of load at risk as an asset loaded above 117% during peak periods based on the relative time that each asset was so loaded.

The imposed licence conditions have now, however, superseded this scenario and whilst the introduced criteria notionally reflects EnergyAustralia's previous standard it is now a strict obligation which must be met. This now means that neither EnergyAustralia is now obliged to address a substation which experiences risk levels in excess of 1%.

The result of applying the 1% load at risk criterion rather than the 117% is that instead of 10 substations requiring as yet unfunded works at the end of the period, EnergyAustralia has forecast that 19 substations would now require work for it to be complaint by the end of the regulatory period, or shortly thereafter. The projects identified in Table 13 below are drawn from those assets that were identified at the time of the Determination as exceeding the target criteria, and substations that were not previously included in the capital program submitted to IPART as they did not reach the required peak demand test discussed in the determination, with the exception of 2 substations Edgeworth and Toronto. Both of these substations were identified as requiring minor works as part of EnergyAustralia's "base case" submission, however the new design planning obligations will require EnergyAustralia to undertake more extensive works that originally forecast.

To ensure that EnergyAustralia only claims the incremental costs of works on these substations EnergyAustralia has indexed the $6 million included in the "base case" to $6.4 million in $2005/06, and deducted the indexed value from the forecast program associated with these substations. Therefore EnergyAustralia submits that the costs for all claimed projects are incremental to the program of works funded under the Determination.

In addition to these variations to EnergyAustralia's forecast capital expenditure program at the time of the Determination, IPART made two general adjustments to EnergyAustralia's "base case" program that must be accounted for in this application. Based on the recommendations from its consultant, IPART reduced EnergyAustralia's replacement capital expenditure by $119 million. However IPART, again acting on advice from its consultants, increased EnergyAustralia's approved augmentation expenditure by $155 million above that sought in the "base case" submitted in the April 2003 submission[19]. The net impact of these two adjustments is such that in comparing the costs of "base case" capital expenditure program to that required by new licence conditions should be reduced by $36[20] million. Escalated into 2005/06 dollar terms, EnergyAustralia had deducted $38.38 from its forecast capital expenditure programs.

Therefore EnergyAustralia has offset this $38.38 evenly against the forecast capital expenditure in this program and that included in the urban 11kV program set out below in section 6.3.7. In this manner EnergyAustralia has attempted to ensure that the incremental programs have been identified against those included in the "base case", and that IPART's financial adjustments have been fully accounted for. In this manner EnergyAustralia submits that it has provided in this application, and sought as a pass through, only those costs that are incremental to the overall financial outcomes provided by the Determination.

The zone substations identified for the two regions are set out in the two tables below.

[19] IPART, NSW Electricity Distribution Pricing 2004/05 to 2008/09 Final Report, 2004, Page 31.
[20] Both of the adjustments made by IPART are in 2003/04 dollar terms. For the purpose of EnergyAustralia's modelling these figures were converted in to 2005/06 dollar terms.

Table 13: Sydney Zone Substations with Load at Risk Exceeding 1% by 30 June 2009*

Arncliffe	Avoca	Blakehurst	Carringbah
Concord	Cronulla	Double Bay	Greenacre Park
Hurstville North	Jannali	Kurnell	Lake Munmorah
Miranda	Pymble	Revesby	Rose Bay
Turramurra	Umina		

*Or works required to ensure compliance shortly thereafter due to forecast load growth.

Table 14: Hunter Region Zone Substations with Load at Risk Exceeding 1%

Broadmeadow	Cardiff	Charlestown
East Maitland	Edgeworth	Swansea
Toronto		

The estimated capital expenditure requirement over the period 2005/6 to 2008/9 for all of the urban zone substations identified in the two tables above is set out in the table below.

Table 15: N-1 Criteria Urban Zone Substation Program Cost Summary

Program	2005/06	2006/07	2007/08	2008/09
Capital expenditure ($M)	15.44	45.33	48.92	42.34
Capex in the Determination ($M)	6.408	6.40	6.40	6.40
Incremental Capex ($M)	9.04	38.93	42.52	35.95
Operating expenditure ($M)	0.12	0.75	1.81	2.84
Total Costs ($M)				**$131.96 million**

6.3.8 N-1 Criteria Distribution Feeders

Schedule 1 of the new licence conditions - Design Planning Criteria – specifies that distribution feeders in urban areas are to have an “N-1” security standard subject to a maximum customer interruption time of 4 hours.

Whilst EnergyAustralia’s 11kV network in urban areas is largely built on an “open ring” concept, some feeders are radial. Equally critical, N-1 requires that capacity be reserved in adjacent feeders to enable them to pick up part or whole of the adjoining feeder's load under outage conditions.

EnergyAustralia's stated **ideal** planning **preference** for the 11kV network is set out below.

> *"The 11kV network in most urban areas comprises radial 11kV feeders with manually switched alternate supply in medium density areas. In these areas the 11kV network is generally planned using a deterministic (n-1) criterion for feeders. In addition, the network is ideally planned so that supply can be fully restored at peak loads in 3 switching steps. The maximum number of switching steps required to restore supply following a failure should not exceed 5 switching steps."* [21]

However, EnergyAustralia is required to manage and prioritise its capital projects within the economic constraints of its regulatory determinations. In particular it was recognised, and indeed a core assumption, in the Determination that EnergyAustralia's network would need to be managed utilising probabilistic risk based criteria rather than deterministic criteria.

In its role as network manager and operator under the economic determinations EnergyAustralia must make investment decisions that balance the economic and service outcomes within reasonable risk tolerances. Although EnergyAustralia has clearly articulated its preferred standard, the standard implemented for each particular project will reflect EnergyAustralia's assessment of the relative risks and costs associated with the various design planning standards. Further, EnergyAustralia differentiates between medium density areas and the general urban environment, which recognises that in some circumstances risk management techniques are the best economic solution, and highlights that EnergyAustralia's stated planning preferences are general guides, not standards.

However, the new licence conditions remove management discretion regarding this balance and obligate EnergyAustralia to meet minimum planning requirements. Therefore, despite EnergyAustralia having started a clear preference for the N-1 standard it is now bound to apply the standard for ALL projects in this category, which was not the case previously.

Therefore, the imposition of the N-1 planning standard and the need to provide support to zone substation augmentations under the new licence conditions require EnergyAustralia to undertake several investments that it would not have otherwise undertaken within the economic confines of the Determination. Indeed, EnergyAustralia's forecast 11kV capital expenditure program submitted to IPART during the recent review process was aimed at providing connections to new loads and any resulting reinforcements, and therefore did not address enhancing switching capabilities.

As mentioned in respect of urban zones IPART did provide additional capital expenditure on the basis of a higher peak demand forecast. This would be in part available for additional feeder augmentation. However IPART also reduced the available capital expenditure for replacement capital expenditure. The net impact of these adjustments is that EnergyAustralia was funded for an additional $38.38[22] million of capital expenditure compared to its "base case". Therefore to ensure that the costs claimed are incremental to the determination as a

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[21] EnergyAustralia, Network Management Plan

[22] As discussed above this is the converted net amount in 2005/06 dollar terms.

whole EnergyAustralia has deducted the additional $38.38 million from the capital expenditure requirements in section 6.3.7 above and from the capital expenditure required for the 11kV works. In this manner EnergyAustralia has ensured that the costs sought are incremental to the outcomes provided in the Determination.

In addressing this licence compliance condition, EnergyAustralia has envisaged a distribution feeder design based on a “5 into 4” concept – i.e. if a feeder fails a maximum of 4 switching operations to adjacent feeders is required to restore supply and is less expensive to implement than a “”4 into 3” design in the immediate future. This design should meet the maximum 4 hour customer interruption time allowed under the licence condition. In order to implement this, it will be necessary to reduce the maximum level of loading on distribution feeders to 80%, and to provide additional interconnection between feeders.

EnergyAustralia has reviewed the utilisation of its 11kV distribution feeders on a case-by-case basis. Currently, the load on 360 feeders exceeds 80% of their design rating in summer, winter or both. In addition, it is expected that another 30 feeders per annum will ‘drift’ over this limit. Therefore, EnergyAustralia expects that approximately 480 feeders will require remediation by 2008/9 in order to achieve compliance with this planning standard.

It should be noted that in the longer term EnergyAustralia believes that utilisation in the order of 65% to 75% is the appropriate target, but is constrained in the immediate future in achieving this, and so has set the target utilisation to 80% as discussed above which achieves current compliance targets. This is derived from the need to move the load from 4 feeders into 3 feeders in the event of an outage on one feeder. The utilisation target range reflects the “lumpiness” of investment and the need to manage variations from the load growth forecasts.

Calculation of the cost of this program has been based on an examination of the cost of completing a number of recent projects that specifically addressed utilisation levels on 1 or more feeders. The average cost, per feeder improved, was of the order of $600,000.

The expected costs of EnergyAustralia’s program are set out in the table below. It should be noted that these costs are incremental to the 11kV augmentation costs included in EnergyAustralia’s April 2003 submission to IPART. The augmentation costs relate to the feeder works required for the connection of upstream and downstream assets and installations, and is not related to design planning considerations as discussed above.

Table 16: N-1 Criteria Distribution Feeder Program Cost Summary

Program	**2005/06**	**2006/07**	**2007/08**	**2008/09**
Capital expenditure ($M)	36.0	85.68	87.39	89.14
Capex in the Determination ($M)	4.80	4.80	4.80	4.80
Incremental Capex ($M)	31.20	80.88	82.60	84.34
Operating expenditure ($M)	0.41	1.88	4.02	6.21
Total Incremental Costs ($M)				**$291.54 million**

6.3.9 N Criteria Non-Urban Zone Substations

Schedule 1 of the new licence conditions – Design Planning Criteria requires that non-urban zone substations with load less than 5MVA may have a security standard of "N", but should have best practice repair time. Whilst relatively few EnergyAustralia substations are impacted, a review has indicated that, in order to meet this criterion, a spare zone transformer suitable for use in small zone substations should be purchased and notionally installed at Merriwa substation.

The estimated capital requirement is set out in the table below.

Table 17: N Criteria Non-Urban Zone Substation Program Cost Summary

Program	2005/06	2006/07	2007/08	2008/09
Capital expenditure ($M)	0	0	0.52	0
Capex in the Determination ($M)	0	0	0	0
Incremental Capex ($M)	0	0	0.52	0
Operating expenditure ($M)	0	0	0.01	0.01
Total Costs ($M)				**$0.54 Million**

6.4 Average Feeder Reliability Program Cost Details (Schedule 2)

EnergyAustralia has undertaken detailed analysis of its current reliability performance at average levels within the four feeder categories. Full consideration has been given to the progressively increasing requirements, future peak demand growth, asset aging, and the need for a margin to accommodate statistical variations in year-to-year data. Energy Australia believes that an allowance of between 10% for Urban Feeders and 15% for Short Rural Feeders is both prudent and justifiable. EnergyAustralia has also recognised that programs put in place to meet individual feeder standards and for the design and planning criteria will heavily impact the average performance of feeder groups.

As a result EnergyAustralia has chosen not to invest specifically in meeting this performance requirement. Instead, EnergyAustralia will rely on its investment program aimed at addressing the performance of the worst performing feeders in each of the feeder categories to meet its current compliance at the average levels. It should be noted that towards the end of the regulatory period there will be a need to extend the individual reliability programs aimed at the rural feeders in order to address the average feeder reliability requirements.

As this work will be more feeder specific due to the low numbers of rural feeders this work has been included in the individual feeder reliability program to ensure that there is no double counting of works for individual and average reliability purposes.

Whilst not included in the costs for this application, it should be noted that the impact of the Outage Management System (OMS)[23] on reported average reliability is likely to involve greater focus on the average reliability requirements in the 2009-14 regulatory period and will be incorporated into EnergyAustralia's submissions for the 2009 distribution review. The improved data quality derived from the introduction of the OMS is expected to increase the reported number of outages on some feeders, and reduce outages on others. This type of outcome is consistent with the findings of the PB consultancy report commissioned by IPART[24], which found that there was an overall +/- 10% accuracy in the reliability information. Therefore, it is possible that the improved data will require significant works to ensure compliance on some feeders that are currently being reported as compliant.

Finally EnergyAustralia will be investing $2.2 million on risk mitigation strategies for feeders within the CBD. This work will focus on mitigating the risk of damage spread in key underground pits, including cable basements at Dalley St zone substation and City South zone substation. The mitigation will include improved segregation and fire mitigation using either cable coatings or active fire fighting systems. History has shown that whilst overall feeder reliability has been good, collateral damage arising from single cable failures has resulted in some unacceptably high SAIDI values for CBD feeders.

6.5 Individual Feeder Reliability Program Cost Details (Schedule 3)

It is recognised that there is a potential for overlap between the reliability program and the planning requirements. For this reason the reliability programs discussed in this section arise as a direct response to the new licence conditions, and avoid the overlap with the planning activities by targeting specific feeders and do not relate to general network enhancements, rather they directly target the reported reliability measures.

In addition, EnergyAustralia is aware that it had included $52.5 million of capital expenditure in the April 2003 submission "base case" for reliability improvement activities[25]. Therefore EnergyAustralia has deducted the remaining "unspent" portion of this $52.5 million from its forecast reliability program. To date EnergyAustralia has invested $3.42[26] million in reliability programs, and therefore has reduced the costs claimed in this application for the forecast reliability program by $3.42 million. The results in an as yet "unspent" portion of $52.42 million of the April 2003 "base case" reliability program to be offset against EnergyAustralia's current forecast reliability program once converted to 2005/06 dollar terms.

In this manner EnergyAustralia has been able to segregate the incremental reliability programs arising from the new licence conditions from those submitted in 2003, and manage the potential overlap between the planning and reliability obligations.

[23] The OMS will provide EnergyAustralia with connectivity to enable it to match customers via their national market identifiers to reported faults.

[24] Review of NSW Distribution Network Service Provider's Measurement and Reporting of Network Reliability, IPART Research Paper RP24, July 2003.

[25] EnergyAustralia's Attachment 10 included $40 million for Sydney reliability improvements and $12.5 million for rural reliability improvements in 2003/04 dollar terms.

[26] In 2004/05 dollar terms.

6.5.1 Summary of the Individual Feeder Program Forecasting Methodology

To develop the individual feeder program EnergyAustralia undertook a detailed analysis of each feeder's performance over the past three years. This analysis excludes generation and transmission, and planned outages. EnergyAustralia then applied the IEEE 2.5 Beta methodology to this data. The resulting "2.5 Beta" threshold was calculated to be 3.74 minutes, resulting in several days being excluded from each of the sample years. This approach is discussed in more detail in the Evans and Peck report included as Attachment 2. The remaining statistical data for each individual feeder was then analysed and compared to the categorised targets for each feeder type set by the new licence conditions, recognising the need to target outcomes 10% better than those specified by the licence conditions as discussed above in section 6.4.

This information provided EnergyAustralia with information highlighting those feeders that demonstrated consistent poor performance relative to the new licence conditions, and highlighted those feeders with observable periods of transient poor performance relative to the new targets. Utilising the data for consistently poor performing feeders EnergyAustralia has been able to establish a program to specifically address these feeders. The data relating to transient poor performance, EnergyAustralia has been able to establish a statistical based annual program to address such poor performance as it arises.

The individual feeder works proposed are generic types of programs that can be commenced or increased in scope in a relatively short time period and leverage off current activities and practices, although in significantly greater proportions.

EnergyAustralia's individual feeder program has been developed recognising that individual feeder non-performance can be transient over time, such that the feeders that are non-compliant in one year may be compliant the next. This scenario suggests that EnergyAustralia's program must encompass a larger proportion of its assets than any single year's performance may suggest. However, as non-performance is not systematic for a large number of the feeders in the programs, the activities for these feeders will consist predominately of minor remedial and augmentation works to address known and potential weaknesses and increased feeder inspections.

EnergyAustralia recognises the need to address both CAIDI and SAIFI issues in these feeders. Addressing SAIFI requires an improvement in the underlying reliability by increasing the level of inspection and preventative maintenance. CAIDI programs will focus primarily on the use of more advanced fault location devices to reduce restoration times, and greater use of distribution automation.

Feeders that have a known and more predictable history of non-performance will more likely require more intensive attention and more substantial works to ensure compliance with the licence conditions.

The quality and granularity of outage data is a known issue. This issue has been commented on in previous reviews and IPART provided revenue to support the development and introduction of an OMS in the Determination. The OMS is expected to be fully operational in the near future, and whilst it will greatly assist EnergyAustralia in targeting outcomes in the future, it is possible that historic data may be shown to have underestimated actual individual performance. To accommodate for the potential variation in the statistical performances used to develop the programs EnergyAustralia has assumed a 5% understatement of historic outcomes. This adjustment is considered prudent management.

6.5.1 Feeder Inspection and Thermovision Program

Visual inspection supplemented by thermovision scanning of poor performing feeders to identify potential defects. Types of work arising from inspections:

- Air Break Switch Repair including replacement of poor performing "U Bolt" connections
- Replacement of aged and unserviceable Air Break Switches
- Removal of Air Break Switches where they are no longer required for operational purposes
- Replacement of poorly performing and aged Under Slung Links
- Replacement of defective Bonds prone to thermal failure (eg split bolt clamps and defective bi-metallic connections)
- Replacement of aged and unserviceable Surge Diverters to improve lightning protection and eliminate nuisance protection operations.
- Installation of 11kV Spacers on overhead lines to prevent conductor clashing in high winds.
- Installation of low voltage Spacers to prevent conductor clashing in high winds.

The inspections and thermovision program and the conductor programs are the only two pre-existing programs that involve capital expenditures, therefore the $52.42 million of the "unspent" reliability costs included in the April submission as shown above in section 6.5 have been deducted from the forecast costs for these programs. The adjustments have been apportioned using the relative capital expenditure for each project.

Table 18: Feeder Inspection and Thermovision Program Cost Summary

Program	2005/06	2006/07	2007/08	2008/09
Capital expenditure ($M)	1.75	3.57	3.64	3.71
Capex in the Determination ($M)	1.12	2.28	2.32	2.37
Incremental Capex ($M)	0.64	1.29	1.32	1.35
Operating expenditure ($M)	2.03	4.13	4.23	4.33
Total Costs ($M)				**$19.32 Million**

6.5.2 *Distribution Automation Program*

Installation of more advanced switches and circuit breakers on lines to permit more discrimination in switching and faster restoration times. Types of work include:

- Replacement of aged and unserviceable Reclosers to improve fault discrimination and reduce nuisance tripping.
- Installation of new Reclosers to increase fault discrimination and reduce number of customers affected by outages – e.g. where an underground feeder has a length of overhead connected to it, the Pole Mounted Switch would disconnect the overhead section before customers connected to the cable were interrupted.
- Installation of new Sectionalisers and Autolinks to increase fault discrimination and reduce the number of customers affected by line outages.

This is a new program that EnergyAustralia is proposing to implement in response to the new licence conditions, and as such no costs for this type of program was included in the Determination and if fully incremental.

Table 19: Distribution Automation Program Cost Summary

Program	**2005/06**	**2006/07**	**2007/08**	**2008/09**
Capital expenditure ($M)	2.60	6.89	8.32	9.82
Capex in the Determination ($M)	0	0	0	0
Incremental Capex ($M)	2.62	6.89	8.32	9.82
Operating expenditure ($M)	0.03	0.16	0.36	0.60
Total Costs ($M)				**$28.77 Million**

6.5.3 *Wildlife Proofing Program*

Installation of insulating barriers on equipment with low insulation clearances to prevent wildlife initiated failure. Types of work include:

- Covering of 11kV underground to overhead bare connections to reduce wildlife related outages such as possums etc.
- Covering of bare transformer connections to reduce wildlife related outages.

Wildlife proofing activities are fully expensed, and therefore were not included in the forecast capital expenditure for reliability improvements quoted in EnergyAustralia's April 2003 submission "base case", and thus are fully incremental to the costs underlying the Determination.

Table 20: Wildlife Proofing Program Cost Summary

Program	2005/06	2006/07	2007/08	2008/09
Capital expenditure ($M)	0	0	0	0
Capex in the Determination ($M)	0	0	0	0
Incremental Capex ($M)	0	0	0	0
Operating expenditure ($M)	0.25	0.61	0.77	0.94
Total Costs ($M)				**$2.57 Million**

6.5.4 Protection and Communication Program

Installation of signalling fault indicators and relays (telephone or visual) to speed fault location. Types of work include:

- Distance to Fault Relays which enable operations staff to quickly determine the approximate location of the faulted section of a long line.
- Installation of Instantaneous Over Current Relays on some feeder sections where not currently installed to increase speed of disconnection and reduce thermal damage to equipment such as Air Break Switches, and Bonds, reducing the probability of future failures.
- Installation of (NEMMCO) Type 5 Energy / Demand Meters in selected substations. As well as providing improved loading information, these meters can be used to signal control room staff that the fault is downstream of that particular substation. This enables field operations to quickly identify and isolate the faulted section.
- Installation of Line Fault Indicators. These are a high power strobe light, or remotely signalling indicators, that serve a similar fault identification function to the Type 5 meter.

This is a new program that EnergyAustralia is proposing to implement in response to the new licence conditions, and as such no costs for this type of program was included in the Determination and if fully incremental.

Table 21: Protection and Communication Program Cost Summary

Program	2005/06	2006/07	2007/08	2008/09
Incremental Capex ($M)	0.50	1.89	4.27	8.07
Capex in the Determination ($M)	0	0	0	0
Incremental Capex ($M)	0.50	1.89	4.27	8.07
Operating expenditure ($M)	0.01	0.04	0.12	0.28
Total Costs ($M)				**$15.16 Million**

6.5.5 Conductor Program

Installation of covered conductors in heavily treed areas, and overhead earthwire on the sub-transmission system to protect against lightning strikes. Types of work include:

- Installation of CCT Conductors on 11kV networks to increase resilience to tree contact and falling branches.
- Installation of 95CC Conductors on 11 kV networks to achieve similar outcomes to those above.
- HV Mains Covers to achieve similar outcomes to those listed above.
- OHEW (Subtrans only) – some older sub-transmission lines were installed without overhead earth wires. Fitting earth wires will reduce susceptibility to lightning strikes and reduce outage frequency.

The inspections and thermovision program and the conductor programs are the only two pre-existing programs that involve capital expenditures, therefore the $52.42 million of the "unspent" reliability costs included in the April submission as shown above in section 6.5 have been deducted from the forecast costs for these programs. The adjustments have been apportioned using the relative capital expenditure for each project.

Table 22: Conductor Program Cost Summary

Program	2005/06	2006/07	2007/08	2008/09
Capital expenditure ($M)	4.95	17.65	23.20	23.77
Capex in the Determination ($M)	3.16	11.25	14.79	15.15
Incremental Capex ($M)	1.80	6.40	8.41	8.62
Operating expenditure ($M)	0.02	0.13	0.33	0.55
Total Costs ($M)				**$26.25 Million**

6.5.6 Mobile Generator and Distribution Substation Program

EnergyAustralia has a small number of mobile generators and distribution substations that have traditionally been used for maintaining supply during planned network outages eg for maintenance. In unusually long unplanned outages for high priority customers they have also been occasionally used. In recent years based on achieving the best commercial outcome a contract arrangement has been put in place with external generator suppliers and the internal fleet reduced accordingly.

With the new licence conditions and the strict targets for SAIDI both at an average, feeder and individual customer or GCSS level EnergyAustralia will now need to proactively use both generators and mobile substations to a far greater degree. Predominately this will be in cases where the outage times will be lengthy leading to non compliance. Accordingly the following expanded usage is forecast and is incremental on the basis of the conditions.

This is a new aspect that EnergyAustralia is planning to introduce into its reliability program, and was not included in the forecast reliability program forecast in the April 2003 submission "base case". Although EnergyAustralia has existing arrangements for the use of mobile generators and distribution substations, EnergyAustralia is planning to acquire 4 mobile distribution substations and lease 4 mobile generators specifically for reliability purposes. These arrangements will provide each of the South, North, Central Coast and Newcastle regions a mobile generator and distribution substation to ease the impact of extended outages. Therefore EnergyAustralia submits that the costs for this program are fully incremental to the Determination.

Table 23: Mobile Generator and Distribution Substation Program Cost Summary

Program	2005/06	2006/07	2007/08	2008/09
Capital expenditure ($M)	0	0.41	0	0
Capex in the Determination ($M)	0	0	0	0
Incremental Capex ($M)	0	0.41	0	0
Operating expenditure ($M)	0	1.17	1.20	1.21
Total Costs ($M)				**$3.99 Million**

6.6 GCSS Program Cost Details

Appendix 3 is a map of EnergyAustralia's service area colour coded to illustrate the application of the GCSS requirements throughout EnergyAustralia's network. EnergyAustralia developed the map by cross-referencing the GCSS requirements by network type and customer density with available ABS data. The resulting map demonstrates the diversity in EnergyAustralia's GCSS obligations and the various "pockets" of differential levels of obligations.

The range and distribution of EnergyAustralia's GCSS obligations poses significant challenges, and is instructive as to the granularity and volume of reliability statistics that EnergyAustralia will need to capture and manage. Moreover, the various pockets of differential GCSS obligations highlight the critical need for EnergyAustralia to engage in regular information campaigns to inform customers as to their guaranteed service standards.

For these reasons EnergyAustralia is cognisant that it must ensure that it has the appropriate contact centre capabilities, data availability and training to manage GCSS related calls. Furthermore, EnergyAustralia must ensure that its systems are sufficiently tested to both ensure compliance and to facilitate ease of payment receipts by customers to reinforce the education and information campaigns.

EnergyAustralia notes that, with the exception of the OMS, the costs associated with the introduction of the GCSS obligations have not previously been funded through regulated prices. Therefore, EnergyAustralia is now seeking the full pass through of the incremental costs associated with the introduction of the GCSS in accordance with the provisions in IPART's Determination.

The implementation of the GCSS licence conditions has been undertaken through several programs as discussed below.

6.6.1 Project Management Costs

To manage the introduction of the GCSS licence conditions EnergyAustralia assembled a project management team to coordinate EnergyAustralia's response throughout the organisation. Without the introduction of the GCSS licence conditions this activity would not have been required to be undertaken and therefore EnergyAustralia submits that these costs are totally incremental. The total incremental cost of this activity is forecast to be $0.144 million.

6.6.1 IT System Development Costs

To ensure that EnergyAustralia has sufficient data regarding outages to assess claims by customers, an Outage Management System (OMS) is required. This system provides EnergyAustralia with the connectivity information cross referenced with NMI data to enable EnergyAustralia to determine which customers have been affected by each outage. However, as highlighted above in section 6.2.2, as part of the Determination process EnergyAustralia proposed to develop and implement an OMS to assist in the network management functions within EnergyAustralia.

IPART subsequently included the capital expenditure for the OMS in the determination. Although not directly referenced in the Determination it is clear from the consistency between the proposed IT capital expenditure and that used in the modelling by IPART that it was indeed recognised. As IPART has provided for the $9 million of capital expenditure costs forecast for the OMS in the Determination, the costs are not incremental and will not be claimed by EnergyAustralia.

In addition to the development and implementation of the OMS, EnergyAustralia needed to develop systems that would enable it to provide customers with customer-specific locational maps to help inform customers, and claims management systems and databases to manage claims received by EnergyAustralia. Without the introduction of the GCSS licence conditions the non-OMS works would not have been required, and therefore EnergyAustralia submits that the costs relating to system improvements other than the development of the OMS are incremental and relate solely to the new licence conditions. The incremental cost of this activity is forecast to be $0.0824 million.

6.6.2 Communication Program Development and Ongoing Costs

To ensure that customers understand their rights under the GCSS licence conditions, EnergyAustralia is required to ensure that it undertakes an annual customer information and awareness program to remind customers of their rights under the GCSS licence conditions.

In addition, EnergyAustralia plans to undertake broader communications regarding GCSS with retailers to ensure that they are aware of how EnergyAustralia will manage the licence conditions and claims for their retail customers that are connected to EnergyAustralia's distribution network.

Without the introduction of the mandatory GCSS licence conditions, the communication programs would not have been required or undertaken. EnergyAustralia therefore submits that the costs relating to the communication program are incremental. The total incremental cost of this activity is forecast to be $0.826 million over the current regulatory period.

6.6.3 Contact Centre Development and Ongoing Costs

The model for GCSS payments adopted by the Minister in the licence conditions is a "claims based" approach, whereby customers must make a claim for poor performance. This model will result in increased calls being managed by EnergyAustralia's contact centre, particularly following EnergyAustralia's planned education campaign takes place. As a result additional systems, processes, training and staff are needed to specifically manage these new types of calls.

These new types of calls would not have been required to be managed in the absence of the GCSS licence conditions, and therefore EnergyAustralia submits that the costs relating to the contact centre program are therefore incremental. The total incremental cost of this activity is forecast to be $0.632 million over the current regulatory period.

6.6.4 Claim Assessment Process Development and Ongoing Costs

The payment to customers of $80 per eligible breach of the licence conditions is central to the regime's effectiveness in providing incentives for the DNSPs' to increase reliability outcomes beyond the current standard. The size of the payments also provides incentives for customers to claim their entitlements and enforce their rights under the GCSS framework. However, the magnitude of the payment also provides incentives for customers to make claims even in circumstances where they are not eligible to receive the payments.

EnergyAustralia has assumed that 100% of eligible customers will claim each year for the purposes of modelling the forecast claims costs that will be incurred. The number of eligible customers has been forecast using EnergyAustralia's historical performance against the GCSS measures. However, EnergyAustralia has not currently forecast the total costs associated with examining and processing ineligible claims, which would be $35.53 per claim[27].

EnergyAustralia believes any forecast error in EnergyAustralia's valid claims costs where customers do not claim their entitlements, will be offset by the processing costs arising from ineligible claims received, which have not been separately identified or included in EnergyAustralia's cost forecasts at this stage. EnergyAustralia submits that this is a pragmatic approach to forecasting costs over the current regulatory period until such time as observable EnergyAustralia specific customer behaviour becomes available.

To determine the expected number of valid claims EnergyAustralia would expect to receive it examined the historic network performance against the GCSS criteria. It was determined that the best historical indicator of future, network performance against the GCSS measures is the most recent full year of data, being 2004/05. From the performance over the most recent financial year EnergyAustralia has forecast annual claims by GCSS category as set out in the table below.

[27] This amount is in real 2005/06 dollar terms, and includes all claims costs excluding cheque processing and fixed annual costs

Table 26: Annual Expected GCSS Claims by Claim Type

GCSS	2006/07	2007/08	2008/09
Duration	33,385	33,385	33,385
Frequency	662	662	13,772
Total	**34,047**	**34,047**	**47,157**

As shown in the table above, EnergyAustralia is expecting the number of claims for the frequency of outages GCSS to significantly increase in the final year of the regulatory period. This is due to the tightening of the limit on the number of outages required for a claim to be made as of 1 July 2008. This is forecast to increase the number of these claims by 13,110 for 2008/09.

Based on the forecast number of claims as set out in Table 26 above, the annual costs of processing these claims are expected to range from $0.736 million in 2005/06 to $2.172 million in 2008/09.

Without the introduction of the GCSS licence conditions such claims and their associated payments would not have been received or have been required to be processed. Therefore EnergyAustralia submits that the costs relating to the claim assessment program are incremental. The total incremental cost of this activity is forecast to be $5.976 million over the current regulatory period.

6.6.5 Claims Costs

Based on the methodology outlined above for establishing the expected number of claims received in each remaining year of the regulatory period, EnergyAustralia has forecast the costs of payments made to customers as ranging from $2.616 million in the 2006/07 financial year to $3.487 million for the 2008/09 financial year.

Without the introduction of the GCSS licence conditions such payments to customers would not have been required to be incurred. Therefore EnergyAustralia submits that all claim payments to customers are incremental. The total incremental cost of this activity is forecast to be $8.656 million over the remainder of the current regulatory period.

6.7 Adjustment Mechanism

EnergyAustralia notes that there are forecasting difficulties associated with assessing the costs to comply with the new licence conditions in light of many exogenous factors.

As an example, there is inherent difficulty in accurately forecasting the likely customer processing and payment costs during the establishment phase of the new GCSS regime. In 2008/09 for instance, each 10 per cent variation between forecast and actual costs for claims processing and payments for the GCSS regime would result in EnergyAustralia (or its customers) experiencing a windfall gain or loss of approximately $600,000. EnergyAustralia believes that the financial impact of these variations may be significant, and that it is not reasonable for a DNSP to face the full impact of such forecast variations. This is particularly the case given that a new obligation has been imposed, but a robust claims history relating to the GCSS regime does not currently exist.

Assessing the costs of complying with the new licence conditions is aggravated by the fact that the pass through rules in the Determination provide for a "one-time-only" application by the DNSP within 90 days of the Positive Change Event/Specific Pass Through Event occurring. To attempt to address the impact of exogenous factors, and to avoid any perception of regulatory "gaming" that may arise regarding the costs included in this pass through application, EnergyAustralia advocates the introduction of an "adjustment mechanism".

EnergyAustralia has obtained advice supporting our contention that it is open to IPART to determine the total "Approved Pass Through Amount" and the amount to be passed through per year (under clauses 14.2(b)(2) and 15.2(b)(2)) by reference to a formula rather than fixed dollar amount. We believe it is possible to do this in a manner that would keep administrative costs and processes to a minimum in recognition of IPART's concerns on this topic that were raised during the review process.

The adoption of an "adjustment mechanism" could mitigate against the risk of the actual costs to comply with the new licence obligations being materially different than the *ex ante* pass through amount allowed by IPART, while at the same time not impacting on any efficiency incentives that may have been intended by IPART in the establishment of the pass through mechanism.

EnergyAustralia looks forward to the opportunity to work with IPART to develop how such an "adjustment mechanism" within the constructs of the Determination could be established, to assist IPART in ensuring that only the actual costs of complying with the new licence obligations, or the costs that are likely to incur, are passed through to customers.

Attachment 1: Design, Reliability and Performance Licence Conditions Imposed on Distribution Network Service Providers by the Minister for Energy and Utilities – 1 August 2005

DESIGN, RELIABILITY AND PERFORMANCE

LICENCE CONDITIONS

IMPOSED ON

DISTRIBUTION NETWORK SERVICE PROVIDERS

BY THE MINISTER FOR ENERGY AND UTILITIES

1 AUGUST 2005

DESIGN, RELIABILITY AND PERFORMANCE LICENCE CONDITIONS IMPOSED ON DISTRIBUTION NETWORK SERVICE PROVIDERS BY THE MINISTER FOR ENERGY AND UTILITIES

EXPLANATORY NOTE

Purpose of the reliability performance conditions:

The Minister for Energy and Utilities has imposed on licences held by distribution network service providers under the *Electricity Supply Act 1995* additional conditions relating to reliability performance.

The purpose of these conditions is to facilitate the delivery of a safe and reliable supply of electricity. The conditions impose design, reliability and performance standards on distribution network service providers. When fully implemented, distribution network service providers will be required to report to the Minister to ensure compliance with the conditions. The new standards are as follows:

Design planning criteria:

The *design planning criteria* set out standards to be used by a distribution network service provider in planning, developing, managing and operating its distribution system to ensure that it:

- meets the *reliability standards*; and
- provides an adequate supply with an appropriate level of redundancy, consistent with its regulatory obligations.

Reliability standards:

The purposes of the *reliability standards* are to:

- define minimum average reliability performance, by feeder type, for a distribution network service provider across its distribution network; and
- provide a basis against which a distribution network service provider's reliability performance can be assessed.

Individual feeder standards:

The purposes of the *individual feeder standards* are to:

- specify minimum standards of reliability performance for individual feeders;
- require a distribution network service provider to focus continually on improving the reliability of its feeders; and
- enable the reliability performance of feeders to be monitored over time.

Customer service standards:

The purpose of the *customer service standards* is to provide financial recognition to eligible customers who have experienced poor reliability of supply from a distribution network service provider.

Commencement:

The licence conditions are imposed by the Minister pursuant to item 6(1)(b) of Schedule 2 of the *Electricity Supply Act 1995*. The conditions are imposed on 1 August 2005 and take effect from that date, except where expressly stated otherwise.

Relationship with existing conditions and other obligations:

These conditions are additional to conditions that the Minister has previously imposed on licences held by distribution network service providers and licence conditions imposed under the *Electricity Supply Act 1995* and other regulatory instruments. These conditions are also supplementary to obligations imposed on distribution network service providers by the *Electricity Supply Act 1995*, the *Electricity Supply (General) Regulation 2001*, the *Electricity Supply (Safety and Network Management) Regulation 2002*, and other regulatory instruments.

Enforcement:

These conditions are enforceable under the *Electricity Supply Act 1995* by the Independent Pricing and Regulatory Tribunal and the Minister. These conditions are not intended to create standards which are enforceable against a licence holder by individual customers.

Consultation:

Before imposing these conditions the Minister undertook consultation with stakeholders including the licence holders, the Independent Pricing and Regulatory Tribunal and the Minister administering the *Protection of the Environment Administration Act 1991*. The Minister has given due consideration to submissions received during consultation.

Reporting:

To allow for the development of business, reporting and information technology systems, condition 18.17 provides that the first performance and audit reports under these licence conditions will not be required until after 1 July 2007. Reliability performance reporting will continue to be implemented under the Electricity Supply (Safety and Network Management) Regulation 2002.

Review:

It is intended that these design, reliability and performance conditions will be reviewed within two years to assess their effectiveness in facilitating the delivery of a reliable supply of electricity at reasonable cost. To ensure a well researched, rigorous and timely review, the process will commence within three months. The Department of Energy, Utilities and Sustainability and Treasury will prepare terms of reference within one month, coordinate the review, appoint an independent consultant and consult with stakeholders, including DNSPs and the Independent Pricing and Regulatory Tribunal.

RELIABILITY PERFORMANCE CONDITIONS

14. Design planning criteria

14.1 A licence holder must comply with the applicable *design planning criteria* in Schedule 1 in relation to all of its *network elements* from 1 July 2009.

14.2 A licence holder must comply with the applicable *design planning criteria* in Schedule 1 in relation to its *network elements* installed from 1 July 2007 from the date of installation.

14.3 A licence holder may agree with a customer to apply higher or lower standards of service at the customer's point of supply than the *design planning criteria* relevant to that customer. In cases where negotiations are with developers rather than the ultimate end-use customer, the licence holder must take into account anticipated end-use customer expectations and asset management considerations.

15. Reliability standards

15.1 Subject to 15.4, a licence holder must not, when *excluded interruptions* are disregarded, exceed in a *financial year* the *SAIDI average standards* that apply to its *feeder types*.

15.2 Subject to 15.4, a licence holder must not, when *excluded interruptions* are disregarded, exceed in a *financial year* the *SAIFI average standards* that apply to its *feeder types*.

15.3 The requirements under this condition 15 are the *reliability standards* and take effect from 1 August 2005.

15.4 The *reliability standards* for the 11 month period from 1 August 2005 to 30 June 2006, are to be calculated by applying 11/12 of the *SAIDI average standards* and 11/12 of the *SAIFI average standards.*

16. Individual feeder performance

16.1 This condition applies where one or more of the feeders of a licence holder exceed the relevant *individual feeder standards* for any 12 month period ending at the end of March, June, September or December, when *excluded interruptions* are disregarded.

16.2 A licence holder must:

(a) immediately investigate the causes for each *feeder* exceeding the *individual feeder standards*;

(b) by the end of the quarter following the quarter in which the *feeder* first exceeded the *individual feeder standards*, complete an investigation report identifying the causes and as appropriate, any action required to improve the performance of each feeder to the *individual feeder standards*; and

(c) complete any actions identified in the investigation report to improve the performance of each feeder to the *individual feeder standards* by the end of the third quarter following the quarter in which each feeder first exceeded the *individual feeder standards*.

16.3 The investigation report is to include a documented rectification plan where action is found to be warranted in order to improve the performance of a feeder to the *individual feeder* standards. The action that is required may involve work to other network elements, or may involve only repair or maintenance work where capital works are not warranted taking into account any one-off events and previous performance trends.

16.4 The requirements under this condition 16 take effect from 1 October 2005, for the 12 month period ending on 30 September 2006.

17. Customer service standards

17.1 A licence holder must pay the sum of $80 (including GST) to a customer where the licence holder exceeds the *interruption duration standard* at the customer's premises and the customer has made a claim to the licence holder within three months of the interruption.

17.2 A licence holder must pay the sum of $80 (including GST) to a customer where the licence holder exceeds the *interruption frequency standard* at the customer's premises in a *financial year* and the customer has made a claim to the licence holder within three months of the end of the *financial year* to which the interruptions relate.

17.3 A licence holder is required to make payments under this condition within one month of receipt of a valid claim.

17.4 A licence holder is required to take reasonable steps (such as publishing information on its website and annually writing to customers) to make customers aware of the availability of payments under condition 17. A licence holder is required to advise customers in writing of the terms of condition 17 before it comes into effect.

17.5 A licence holder is required to make only one payment of $80 to a customer per premises in a financial year for exceeding the *interruption frequency standard*.

17.6 A licence holder is required to pay no more than $320 under condition 17 to a customer per premises in any one financial year.

17.7 A payment under this condition does not:

(a) In any way alter or diminish any rights that a customer may have against any person under any trade practices or other applicable legislation, common law or contract;

(b) Represent any admission of legal liability by the licence holder; or

(c) Alter, vary or exclude the operation of the section 119 of the new *National Electricity Law* or any other statutory limitations on liability or immunities applicable to a licence holder.

17.8 The requirements under this condition 17 (aside from condition 17.4) take effect from 1 July 2006.

18. Performance monitoring and reporting

Design planning criteria report

18.1 Subject to Clause 18.17 a licence holder must submit an annual *design planning criteria* report to the Minister by 30 September each year in relation to the following matters:

(a) each of its *network elements* or classes of network elements that did not comply with the *design planning criteria* in Schedule 1 on 1 July of the relevant year;

(b) the remedial action that it intends to take to ensure compliance of those feeders and substations with the *design planning criteria* in Schedule 1; and

(c) any other matter formally notified by the Minister in writing.

Reliability standards report

18.2 Subject to clause 18.17 a licence holder must submit a quarterly reliability standards report to the Minister within one month of the end of each *quarter*.

18.3 Subject to clause 18.17 each reliability standards report must include the following matters for the preceding *quarter* and for the previous 12 month period to the end of that *quarter*:

(a) performance against the *SAIDI average standards* and *SAIFI average standards* by *feeder type*, disregarding *excluded interruptions*;

(b) reasons for any non-compliance by the licence holder with the *reliability standards* and plans to improve performance; and

(c) any other matter formally notified by the Minister in writing.

Individual feeder standards report

18.4 Subject to clause 18.17 a licence holder must submit, within one month of the end of each *quarter*, a quarterly *individual feeder standards* report to the Minister on feeders that did not comply with the *individual feeder standards* during the previous 24 month period, together with, for each feeder:

(a) the date at which the feeder first failed to comply, together with the actual *SAIDI* and *SAIFI* performance of the feeder;

(b) details of the remedial action that the licence holder intends taking, or has taken, to improve the performance of those feeders; and

(c) the date of completion of the remedial action plan, and the actual *SAIDI* and *SAIFI* performance of the feeder during the 12 month period following completion of the remedial action.

Customer service standards report

18.5 Subject to clause 18.17 a licence holder must submit a quarterly customer service standards report to the Minister on the following matters within one month of the end of each *quarter*, for the preceding *quarter* and for the previous 12 month period to the end of that *quarter:*

(a) the number of payments given under condition 17 to customers serviced from each feeder type;

(b) the number of claims under condition 17 by category; and

(c) the number of rejected claims under condition 17 by category.

Major incident reporting

18.6 A licence holder must report to the Minister within 24 hours any major network incidents involving significant injury to persons, loss of property or widespread supply interruptions (e.g. involving the simultaneous interruption of numerous high voltage feeders or the loss of electricity to one or more sections of distribution busbar). High level severity incidents should be advised immediately.

Independent audit report

18.7 Subject to clause 18.17, an independent audit must be conducted after the end of each financial year to audit the licence holder's performance against the:

(a) *design planning criteria;*

(b) *reliability standards*;

(c) *individual feeder standards*; and

(d) *customer service standards*.

18.8 A licence holder is required to nominate a person to conduct the independent audit by notice in writing to IPART. The licence holder must give notice in accordance with any time specified by IPART in writing to the licence holder, or, if no time has been specified, no later than 1 July of the year in which the report is to be submitted to the Minister and IPART.

18.9 The person nominated is to be a person who is:

(a) independent of the licence holder; and

(b) competent to exercise the functions of an auditor in respect of the matters to be audited.

18.10 The nomination of an auditor by a licence holder ceases to have effect if IPART advises the licence holder, by notice in writing, that the nomination is not acceptable or has ceased to be acceptable.

18.11 IPART may nominate an auditor to carry out an audit, and the person so nominated is taken to have been nominated by the licence holder, if:

(a) the nomination of an auditor by the licence holder ceases to have effect; or

(b) the licence holder fails to nominate an auditor to carry out the audit in accordance with any requirements specified by IPART by notice in writing to the licence holder.

18.12 Subject to clause 18.17 a licence holder must provide a copy of the auditor's report by 30 September each year to IPART and the Minister.

General matters concerning reports

18.13 Where the Minister determines the format of a report required by this condition, a licence holder must submit the report in that format.

18.14 The Minister may from time to time establish guidelines to be followed by the licence holder in complying with reports required by this condition and the licence holder must comply with any such guidelines.

18.15 The Minister may from time to time require, by notice in writing to the licence holder, further reports relating to these licence conditions including, without limitation, reports relating to capital expenditure works, network refurbishment and maintenance programs.

18.16 A licence holder must provide a report submitted to the Minister under this condition to IPART, if requested to do so by IPART by notice in writing.

Timing of initial reports

18.17 To allow adequate time to adopt appropriate systems, reports until 1 July 2007 shall be made under the Electricity Supply (Safety and Network Management) Regulation 2002. From 1 July 2007 reports against the new standards will be submitted as follows:

(a) Within three months of the end of each financial year on compliance with *design planning criteria*, the first being by 30 September 2007;

(b) Within three months of the end of each financial year, for each annual audit report, the first being by 30 September 2007; and

(c) Within one month of the end of each quarter for reports on *reliability standards*, *individual feeder standards* and *customer service standards*, the first being by 31 July 2007.

19 Interpretation and definitions

19.1 These licence conditions are imposed by the Minister pursuant to item 6(1)(b) of Schedule 2 of the Act.

19.2 These licence conditions are in addition to other licence conditions imposed by the Minister, licence conditions under the Act or Regulations, and other obligations imposed on licence holders by the Act and Regulations.

19.3 These conditions are imposed on 1 August 2005 and take effect from that date, except where otherwise stated in the conditions or the Schedules to the conditions.

19.4 Expressions used in these licence conditions that are defined in the Act or the Regulations made under the Act have, unless otherwise stated, the meanings set out in the Act or the Regulations.

19.5 In these licence conditions:

Act	means the *Electricity Supply Act 1995.*
Best practice repair time	means the minimum practicable time period to restore supply.
CBD feeder	means a feeder supplying predominantly commercial high-rise buildings, supplied by the Sydney triplex underground distribution network
customer	means a wholesale customer or a retail customer in the licence holder's distribution district.
design planning criteria	means the load magnitude, security standard and customer interruption time specified in Schedule 1 to these conditions.

distribution feeder	means a high-voltage line operating over 1000V and at or below 22kV that connects between a zone substation and a distribution substation, excluding short radial sections off the trunk feeder used to supply a small number of distribution substations (e.g. a spur line into a peninsula or valley).
distribution substation	means a *substation* forming part of the distribution system, which provides the network link between a *distribution feeder* and elements of the distribution system below 1000V.
excluded interruptions	means excluded interruptions listed in Schedule 4 to these conditions.
feeder	means a *distribution feeder.*
feeder type	means a *CBD feeder*, *long-rural feeder*, *short-rural feeder* or *urban feeder* as the case may be.
financial year	means a year commencing 1 July and ending 30 June.
Greater Sydney Metropolitan Area	the region bounded by, and including: ▪ Kiama, Shellharbour, Wollongong, Campbelltown, Camden, Liverpool, Penrith, Hawkesbury, Gosford, Wyong, Lake Macquarie, Newcastle and Maitland local government areas; and ▪ the east coast of New South Wales.
GST	has the meaning it has in the *A New Tax System (Goods and Services Tax) Act 1999* (Cth).
individual feeder standards	means the individual feeder standards in Schedule 3 to these conditions.
interruption	means any temporary unavailability of electricity supply to a customer associated with an outage of the distribution system including outages affecting a single premises, but does not include disconnection.
interruption duration standards	means the interruption duration standards set out in Schedule 5 to these conditions.
interruption frequency standards	means the interruption frequency standards set out in Schedule 5 to these conditions.

IPART	means the Independent Pricing and Regulatory Tribunal established under the *Independent Pricing and Regulatory Tribunal Act 1992*.
licence holder	means the holder of a distribution network service providers' licence.
load-at-risk	means the difference between the load and the maximum supportable load following a credible contingency.
long rural feeder	means a feeder with a total feeder length greater than 200 km which is not a *CBD feeder* or an *urban feeder*.
major event day	means a day determined under Schedule 6.
metro rural	means all areas within the *Greater Sydney Metropolitan Area* other than *metro urban* areas.
metro urban	means urban areas within the *Greater Sydney Metropolitan Area* with a population exceeding 5,000.
Minister	means the Minister administering the Act.
MVA	means mega volt amperes.
N-1, N-2	N-1 is designing for one unplanned system element contingency outage and N-2 is designing for two. An unplanned contingency outage will result in: ▪ *Interruption* to customers up to the time indicated; ▪ Acceptable voltage levels being maintained at the secondary busbars of transformers; ▪ Remaining in-service elements being loaded within their thermal limits. This standard is based on consideration of credible contingencies generally limited to major plant with either significant failure rates and/or requiring routine outages for maintenance e.g. zone transformers
network elements	means the following parts of a licence holder's distribution system: *sub-transmission lines, sub-transmission substations, zone substations, distribution feeders and distribution substations*.

non-metro rural	means all areas outside of the *Greater Sydney Metropolitan Area* other than *non-metro urban* areas.
non-metro urban	means any urban area outside of the *Greater Sydney Metropolitan Area* with a population exceeding 5,000.
planned interruption	means an *interruption* for which advance notice has been provided or which has been requested by a customer.
quarter	means a period of three months commencing 1 January, 1 April, 1 July and 1 October as the case may be.
regional centre	means: until 30 June 2012, the towns of Tweed Heads, Wagga Wagga, Coffs Harbour (including Sawtell), Albury, Port Macquarie, Queanbeyan, Orange, Tamworth, Dubbo, Bathurst and Lismore; and also: from 1 July 2012, the additional towns of Goulburn, Forster-Tuncurry, Armidale, Broken Hill, Grafton, Griffith, Ballina and Taree.
Regulations	means Regulations made under the Act.
regulatory period	means the period for which the economic regulator provides for a price path for network income and for the purpose of this document will be taken to be a period of five years.
reliability standards	means the requirements imposed under condition 15 of these conditions.
SAIDI	means the sum of the duration of each sustained customer interruption (measured in minutes), divided by the total number of customers (averaged over the *financial year*) of the licence holder.
SAIFI	means the total number of sustained customer interruptions divided by the total number of customers (averaged over the *financial year*) of that licence holder.
SAIDI average standards	means the standards set out in item 1, Schedule 2.
SAIFI average standards	means the standards set out in item 2, Schedule 2.

SAIDI individual feeder standards	means the standards set out in item 1, Schedule 3.
SAIFI individual feeder standards	means the standards set out in item 2, Schedule 3.
short-rural feeder	means a feeder with a total feeder route length less than 200 km, and which is not a *CBD feeder* or an *urban feeder*.
substation	means a part of an electrical network, confined to a given area, mainly including ends of transmission or distribution lines, electrical switchgear and control gear, and one or more transformers. A substation generally includes safety or control devices (for example protection).
sub-transmission	means those parts of the distribution system (including power lines and towers, cables and substations as the case may be) that transfer electricity from the regional bulk supply points supplying areas of consumption to individual *zone substations*, operating at nominal voltages between 132 kV and 33 kV inclusive, that may also fulfil a transmission role by operating in parallel to, and providing support to, the higher voltage transmission network.
table 1	means the table in Schedule 5 to these conditions.
third party	does not include a person or body contracted or authorised by the licence holder to take action, or any animal or plant life.
urban feeder	means a feeder with actual maximum demand over the reporting period per total feeder route length greater than 0.3 MVA/km and which is not a *CBD Feeder*, *short-rural* feeder or *long-rural feeder*.
zone substation	means a *substation* forming part of the distribution system, which provides the network link between the *sub-transmission* network and elements of the distribution system at or below 22kV.

SCHEDULE 1
DESIGN PLANNING CRITERIA

Network Element	**Load Type**	**Load Magnitude**	**From 1 July 2009 (all *network elements*) 1 July 2007 to 30 June 2009 (new *network elements*)**	
			Security Standard	**Customer Interruption Time**
Sub Transmission Line	CBD[1]	Any	N-2	< 1 minute (1st outage); <1 hour (2nd outage)
	Urban & Non-Urban[2]	≥ 5 MVA	N-1	< 1 minute
	Non-Urban[2]	< 5 MVA	N	*Best practice repair time*
Sub Transmission Substation	CBD[1, 3]	Any	N-2	< 1 minute (1st outage); <1 hour (2nd outage)
	Urban & Non-Urban[3]	Any	N-1	< 1 minute
Zone Substation	CBD[1, 3]	Any	N-2	< 1 minute (1st outage); <1 hour (2nd outage)
	Urban & Non-Urban[2, 3]	≥ 5 MVA	N-1	< 1 minute
	Non-Urban[2]	< 5 MVA	N	*Best practice repair time*
Distribution Feeder	CBD[1, 6]	Any	N-1	< 1 minute
	Urban (town ≥ 15,000[4])[5]	Any	N-1	< 4 Hours
	Urban (town < 15,000[4])	Any	N	*Best practice repair time*
	Non-Urban	Any	N	*Best practice repair time*
Distribution Substation	CBD[1]	Any	N-1	< 1 minute
	Urban & Non-Urban	Any	N	*Best practice repair time*

1. CBD means the Sydney central business district only.
2. For Integral Energy Australia, 5MVA is replaced by 10MVA until 30 June 2014. For Country Energy, 5MVA is replaced by 15MVA.
3. In any *financial year*, *load-at-risk* is permitted where the probability is <1% that load may not be able to be sustained following a failure. This applies except :
    a. for sub-transmission and Sydney CBD zone substations, all *load-at-risk* must be eliminated from 30 June 2012;
    b. for all other zone substations ≥20MVA, all *load-at-risk* must be eliminated within the next two *regulatory periods* following the present *regulatory period*;
4. For Country Energy, "town ≥ 15,000" is replaced by "*regional centres"* and "town < 15,000" is replaced by "other than *regional centres"*
5. This standard does not apply to interim supplies to developments prior to completion of the development.
   The timeframe is expected based on the need to carry out 3-5 manual field switching operations and does not apply in cases of numerous coincident outages (e.g. during major storms), traffic gridlock or other factors outside the control of the electricity distributor. For Integral Energy Australia existing urban *distribution feeders* must comply by the end of the next *regulatory period* following the present *regulatory period*.
6. The actual security standard is an enhanced N-1. For a second distribution feeder loss in the CBD, restricted essential load can still be supplied (approximately 50% of peak load; percentage of load at time of outage is dependent on time of year and daily load cycle).

SCHEDULE 2 – RELIABILITY STANDARDS

1. SAIDI average standards

SAIDI – Average Reliability Duration Standards (Minutes per customer)						
EnergyAustralia						
Feeder Type	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**
CBD	60	57	54	51	48	45
Urban	90	88	86	84	82	80
Short-rural	400	380	360	340	320	300
Long-rural	900	860	820	780	740	700
Integral Energy						
Feeder Type	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**
Urban	90	88	86	84	82	80
Short-rural	300	292	284	276	268	260
Long-rural	n/a	n/a	n/a	n/a	n/a	n/a
Country Energy						
Feeder Type	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**
Urban	140	137	134	131	128	125
Short-rural	340	332	324	316	308	300
Long-rural	750	740	730	720	710	700

2. SAIFI average standards

SAIFI – Average Reliability Frequency Standards (Number per customer)						
EnergyAustralia						
Feeder Type	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**
CBD	0.35	0.34	0.33	0.32	0.31	0.3
Urban	1.3	1.28	1.26	1.24	1.22	1.2
Short-rural	4.4	4.2	3.9	3.7	3.4	3.2
Long-rural	8.5	8	7.5	7	6.5	6
Integral Energy						
Feeder Type	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**
Urban	1.3	1.28	1.26	1.24	1.22	1.2
Short-rural	2.8	2.76	2.72	2.68	2.64	2.6
Long-rural	n/a	n/a	n/a	n/a	n/a	n/a
Country Energy						
Feeder Type	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**
Urban	2	1.96	1.92	1.88	1.84	1.8
Short-rural	3.3	3.24	3.18	3.12	3.06	3.0
Long-rural	5	4.9	4.8	4.7	4.6	4.5

SCHEDULE 3 – INDIVIDUAL FEEDER STANDARDS

1. SAIDI Individual Feeder Standards

SAIDI – Standards (Minutes per customer)	
EnergyAustralia	
Feeder Type	**Minutes per customer**
CBD	100
Urban	350
Short-rural	1000
Long-rural	1400
Integral Energy	
Feeder Type	**Minutes per customer**
Urban	350
Short-rural	800
*Long-rural**	1200
Country Energy	
Feeder Type	**Minutes per customer**
Urban	400
Short-rural	1000
Long-rural	1400

2. SAIFI Individual Feeder Standards

SAIFI – Standards (Number per customer)	
EnergyAustralia	
Feeder Type	**Number per customer**
CBD	1.4
Urban	4
Short-rural	8
Long-rural	10
Integral Energy	
Feeder Type	**Number per customer**
Urban	4
Short-rural	6.5
*Long-rural**	10
Country Energy	
Feeder Type	**Number per customer**
Urban	6
Short-rural	8
Long-rural	10

SCHEDULE 4 - EXCLUDED INTERRUPTIONS

The following types of *interruptions* (and no others) are *excluded interruptions:*

(a) an *interruption* of a duration of one minute or less;

(b) an *interruption* resulting from:

- (i) load shedding due to a shortfall in generation;
- (ii) a direction or other instrument issued under the *National Electricity Law*, *Energy and Utilities Administration Act 1987*, the *Essential Services Act 1988* or the *State Emergency and Rescue Management Act 1989* to interrupt the supply of electricity;
- (iii) automatic shedding of load under the control of under-frequency relays following the occurrence of a power system under-frequency condition described in the *Power System Security and Reliability Standards* made under the National Electricity Rules;
- (iv) a failure of the shared *transmission system*;

(c) a *planned interruption*;

(d) any *interruption* to the supply of electricity on a licence holder's distribution system which commences on a *major event day*; and

(e) an *interruption* caused by a customer's electrical installation or failure of that electrical installation.

SCHEDULE 5 – CUSTOMER SERVICE STANDARDS

Interruption duration standard:

1. The *interruption duration standard* is the maximum duration, set out in column 2 of *table 1*, of an *interruption* to a customer's *premises* located in the relevant area in column 1 of *table 1*

Interruption frequency standard:

2. The *interruption frequency standard* is the maximum number of *interruptions* in a financial year set out in column 3 of *table 1*, to a customer's premises located in the relevant area in column 1 of *table 1*:

Table 1

Column 1	**Column 2**	**Column 3**	
Type of area in which customer's premises is located	***Interruption duration standard*** **(hours)**	***Interruption frequency standard*** **(number of interruptions)**	
		From 1 July 2006 to 30 June 2008	**After 1 July 2008**
Metro urban	10	9	6
Metro rural	18	15	12
Non-metro urban	18	12	9
Non-metro rural	24	20	15

Interruptions to be disregarded

3. In calculating the *interruption duration standard* or the *interruption frequency standard* the following types of *interruptions* (and no others) are excluded:

(a) an *interruption* of a duration of one minute or less;

(b) an *interruption* resulting from the following external causes:

(i) a shortfall in generation;

(ii) a failure or instability of the shared *transmission system*;

(iii) a request or direction from the State Emergency Service; or

(iv) a failure of another licence holder's *distribution system*.

(c) a *planned* interruption;

(d) an *interruption* within a region in which a natural disaster has occurred and:

(i) the Minister responsible for administering the *State Emergency Service Act* has notified the Commonwealth of the occurrence of an eligible disaster under the *Natural Disaster Relief Arrangements* in respect of that natural disaster for that region; and

(ii) the *interruption* occurred during the period for which the *Natural Disaster Relief Arrangements* have been notified.

(e) an interruption caused by a storm which is categorised by the Bureau of Meteorology as a "severe storm".

(f) an interruption caused by *third party* actions other than animal or vegetation interference (e.g. vehicle-hit-pole, vandalism) where the interruption is not also caused by any failure of the licence holder to comply with relevant plans, codes, guides or standards (e.g. low conductor clearance).

SCHEDULE 6 – MAJOR EVENT DAY

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Explanation and Purpose

The following process ("**Beta Method**") is used to identify *major event days* which are to be excluded from the *reliability standards* and *individual feeder standards*.

Its purpose is to allow major events to be studied separately from daily operation, and in the process, to better reveal trends in a daily operation that would be hidden by the large statistical effect of major events.

A *major event day* under the Beta Method is one in which the daily total system (i.e. not on a *feeder type* basis) *SAIDI* value ("**daily *SAIDI* value**") exceeds a threshold value, $T_{MED.}$ The *SAIDI* is used as the basis of determining whether a day is a *major event day* since it leads to consistent results regardless of utility size and because *SAIDI* is a good indicator of operational and design stress.

In calculating the daily total system *SAIDI*, any *interruption* that spans multiple days is deemed to accrue on the day on which the *interruption* begins. That is, all minutes without supply resulting from an *interruption* beginning on a *major event day* are deemed to have occurred in the *major event day*, including those minutes without supply occurring on following days.

Determining a major event day

The *major event day* identification threshold value T_{MED} is calculated at the end of each *financial year* for each *DNSP* for use during the next *financial year* as follows:

a) Collect daily *SAIDI* values for the last five *financial years*. If fewer than five years of historical data are available, use all available historical data for the lesser period.

b) Only those days that have a daily *SAIDI* value will be used to calculated the T_{MED} (i.e. days that did not have any *interruptions* are not included).

c) Take the natural logarithm (In) of each daily *SAIDI* value in the data set.

d) Find α (Alpha), the average of the logarithms (also known as the log-average) of the data set.

e) Find β (Beta), the standard deviation of the logarithms (also knows as the log-standard deviation) of the data set.

f) Complete the major event day threshold T_{MED} using the following equation:

$$T_{MED} = e^{(\alpha + 2.5\beta)}$$

g) Any day with daily *SAIDI* value greater than the threshold value T_{MED} which occurs during the subsequent *financial year* is classified as *a major event day.*

Treatment of a major event day

To avoid doubt, a *major event day*, and all *interruptions* beginning on that day, are excluded from the calculation of a *DNSP's SAIDI* and *SAIFI* in respect of all of its *feeder types*.

Attachment 2: Evans & Peck Report

ENERGYAUSTRALIA

Report on Implications of Imposition of Planning and Reliability Standards on Capital and Operational Expenditure

November 2005

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1 EXECUTIVE SUMMARY

On 1 August 2005 the Minister for Energy and Utilities imposed "Design, Reliability and Performance Licence Conditions" on Distribution Network Service Providers operating in NSW.

EnergyAustralia engaged Evans & Peck to assist in the identification of the programs required to prudently manage these licence compliance conditions. We were asked to provide a high level review of the extent of the program, the cost reasonableness of the proposed response and to challenge EnergyAustralia's assumptions. Concurrent with this, EnergyAustralia has prepared a submission to the Independent Pricing and Regulatory Tribunal (IPART) seeking additional funding to implement the programs. A number of issues raised by Evans & Peck have been reflected in the IPART submission.

In discharging our responsibilities, we have relied heavily on information supplied by EnergyAustralia. In a number of instances there are recognised deficiencies in the data due to the short time frame in which this program has been developed, and known deficiencies in reliability information. These will be redressed as major information technology projects in place are completed. Notwithstanding, we believe that the data used is the best available. In a number of cases, we have challenged the inclusion of projects and EnergyAustralia's submitted program incorporates the findings of our review.

We are in agreement with EnergyAustralia that the new licence conditions will impact significantly in the following areas:

- The need to achieve an N-2 supply security standard on Sub-transmission Substations, Sub-transmission Lines and Zone substations in the Sydney CBD. EnergyAustralia currently applies a deterministic N-1 security standard on these network elements. Whilst the compliance requirements can be incorporated into the CBD zone substation under construction (City North), installation of additional transformers in Dalley St, City South and City Central is impractical. This requirement will accelerate the need for a major new city zone substation, and major 11kV interconnection works.
- The need, as a matter of licence compliance, to achieve a notional security standard of "N-1" and reduce the load at risk on Urban and Non Urban Sub-transmission Feeders and Zone Substations to less than 1%. Whilst this policy is generally in accord with EnergyAustralia's preferred approach, the compliance aspect necessitates an acceleration of work in a number of substations.
- The need to achieve an N-1 (4 hour switching) security standard on the vast majority of EnergyAustralia's 11kV network. This requires interconnection between feeders, and the reservation of capacity in feeders so that they can absorb the additional load of a faulted feeder. Whilst EnergyAustralia's 11kV distribution feeder network has high levels of interconnection, this is not unilateral. There are a

large number of feeders that do not have sufficient spare capacity to meet this requirement.

- The need to meet individual reliability standards on Urban, Short Rural and Long Rural Feeders. Over the last 3 years, approximately 9% of feeders would have failed to meet the compliance requirement in one or more years. Importantly, the set of feeders not meeting compliance requirements changes from year to year. This will necessitate a broad compliance program to manage feeders with intermittent performance outcomes.
- The need to meet improving reliability requirements on rural feeders in general. The Licence Conditions require a significant improvement in the average reliability of the Short Rural and Long Rural groups. Evans & Peck does not believe that the program to achieve individual feeder standards alone will result in sufficient overall improvement to meet the compliance program. In the case of Urban Feeders, we believe the individual feeder program, and the impact of the "N-1" (4 hour) design standard will be sufficient to achieve overall standards.

Based on the information available, our review supports EnergyAustralia's view that the following will be required over the period 2005/6 to 2008/9 to prudently discharge compliance obligations:

- Incorporation of a 5th transformer into City North
- Acceleration of land acquisition, design and some construction for a new CBD zone substation
- Acceleration of work on two Sub-transmission substations. One of these substations is regulated as a transmission asset.
- New work, or advancement of work, on twelve Sub-transmission Feeders. Four of these feeders are regulated as transmission assets.
- A variety of new or advanced works on approximately 30 zone substations
- The need to relieve loading on up to 480 11kV distribution feeders
- Implementation of suite of 11kV feeder reliability performance programs, as shown in the following table – based on the full implementation of EnergyAustralia's proposed Schedule 1 compliance program.

Reliability Compliance Programs Arising from Schedule 2 (Average) and Schedule 3 (Individual) of Licence Compliance Conditions

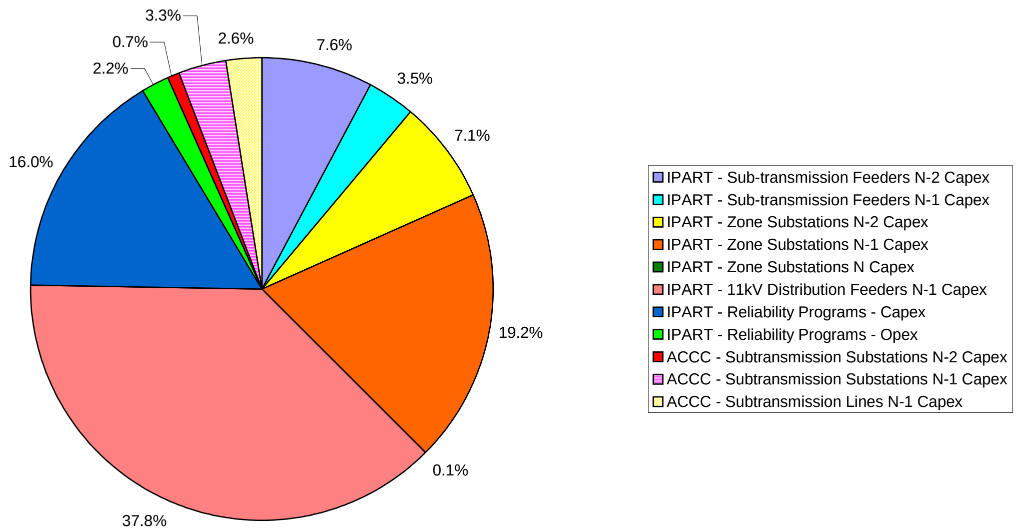
	CBD		Urban		Short Rural		Long Rural	
Year	Average Standard	Individual Standard	Average Standard	Individual Standard	Average Standard	Individual Standard	Average Standard	Individual Standard
2005/06	✘[1]	✘	✘	✓	✘	✓	✘	✓
2006/07	✘	✘	✘	✓	✘	✓	✘	✓
2007/08	✘	✘	✘	✓	✓	✓	✓	✓
2008/09	✘	✘	✘	✓	✓	✓	✓	✓

EnergyAustralia is impacted by two regulatory determinations. Distribution assets are the subject of a determination made by IPART. Transmission assets are the subject of an Australian Competition and Consumer Commission determination, which is now administered by the Australian Energy Regulator. Expenditure requirements have been split into the appropriate jurisdiction. Some of the programs are categorised as operational expenditure, with the majority being capital.

In determining the expected cost of the licence compliance program, we have relied on EnergyAustralia's own estimates. We have sought to ensure that those most responsible, qualified and experienced in the relevant areas have provided the estimates. Rules of thumb have been applied to confirm the reasonableness of the cost assigned to each project.

The estimated combined cost of capital and operational expenditures over the period 2005/6 to 2008/9 (in both regulatory jurisdictions) required to meet the new licence compliance program~~s~~ exceeds $650 million ($2005/6), split as shown in the following chart:

ENERGY AUSTRALIA RELIABILITY COMPLIANCE PROGRAM 2005/6 to 2008/9



Approximately 7% of this expenditure relates to transmission assets that are subject to an ACCC determination. Some adjustment of these values is required to recognise work budgeted under the previous Determination, to account for timing of cash flow and to recognise operational expenditure arising from the expanded asset base. These adjustments have been performed by EnergyAustralia in preparing their submission.

[1] *Refer comments re need for risk mitigation strategy to limit spread of impact from individual feeder faults*

2 BACKGROUND

In early September 2005, EnergyAustralia engaged Evans & Peck to assist in the preparation of a submission by EnergyAustralia to the Independent Pricing and Regulatory Tribunal seeking appropriate funding to enable capital and operational expenditure programs to be put in place to meet EnergyAustralia's obligations under the "Design, Reliability and Performance Licence Conditions Imposed on Distribution Network Service Providers by the Minister for Energy and Utilities (1 August 2005)".

Whilst our primary role was to provide assistance in the preparation of that submission, in so doing we were also asked to:

- Conduct a high level review of the methodology used by EnergyAustralia to identify capital and operational expenditure needs to meet the planning requirements inherent in the above Conditions.
- Provide additional numerical analysis of the reliability data held by EnergyAustralia in order to make a preliminary estimate of the inherent statistical variability in their reliability performance.
- On the basis of this statistical analysis and other information, assist in the identification and targeting of reliability enhancement programs that will substantially increase EnergyAustralia's likelihood of sustained compliance with the new Conditions over the short to medium term.
- Quantify both the individual and cumulative effects of each program so as to ensure that unnecessary programs (and hence capital and operational expenditure) that would result in a substantial over achievement of Conditions are eliminated.
- Challenge EnergyAustralia's assumptions.

3 RELIABILITY STANDARDS COMPLIANCE

3.1 CALCULATION OF HISTORICAL RELIABILITY PERFORMANCE

In response to our request, EnergyAustralia has provided us with daily SAIDI and SAIFI data covering the period 1 July 2002 to 30 June 2005. Aggregate daily data has been provided for:

- CBD Feeders
- Urban Feeders
- Short Rural Feeders
- Long Rural Feeders

This data excludes generation and transmission outages, and planned outages. We have applied the IEEE 2.5 Beta methodology to this data, and found the "2.5 Beta" threshold to be 3.74 minutes. Over the three years, this results in the following dates for exclusion:

Excluded Events Arising from 2.5Beta Method		
2002 / 03	2003 / 04	2004 / 05
24 July 2002	24 Aug 03	18 July 04
26 Nov 2002	23 Jan 04	1 October 04
8 Jan 2003		13 October 04
24 Aug 03		27 October 04
		1 December 04
		2 February 05
		19 February 05
		24 March 05
		30 June 05

We have only used 3 years of data in determining the "2.5 Beta" threshold. The methodology specifies the use of 5 years. EnergyAustralia has advised that their calculation utilising 5 years data results in a slightly lower threshold. Two additional dates - 18 January 2003 and 24 July 2003 are then on the cusp of exclusion. We have excluded these additional days for the purpose of the following analysis.

Based on the daily data provided, we have independently calculated feeder SAIDI and SAIFI after removal of allowed exclusions. The resultant values are as follows:

Calculated Average Performance by Feeder Type after Application of IEEE 2.5 Beta Method								
Year	CBD		Urban		Short Rural		Long Rural	
	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI
2002/03	50.63	.17	65.33	.90	299.71	3.65	481.00	5.01
2003/04	110.45	.18	74.54	1.06	343.63	3.70	858.37	8.71
2004/05	9.40	.10	75.96	1.07	243.25	2.79	964.77	6.90

There are no material differences between these values and those calculated by EnergyAustralia and separately advised to Evans & Peck.

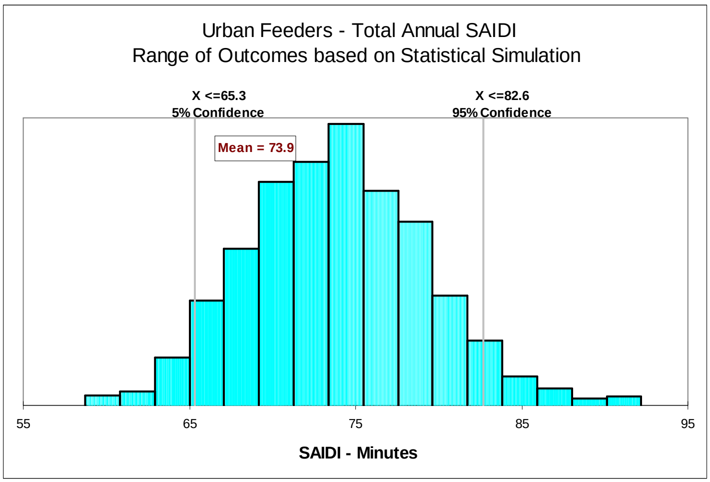
3.2 INHERENT STATISTICAL VARIATION IN RELIABILITY DATA

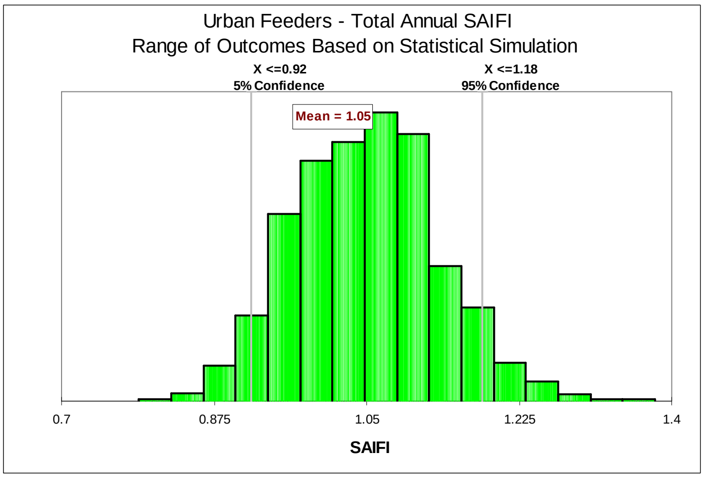
The IEEE "2.5 Beta" method, by removing certain excluded events, attempts to normalise reliability performance measures from year to year. However, a key issue to be addressed in establishing reliability programs is to adequately address the risks associated with the intrinsic statistical variation that still resides in annual reliability measures. By way of example, this is particularly evident in the case of EnergyAustralia's Long Rural Feeders where the variation between the 'best' year and the 'worst' year over the 3 years shown above is 200%. Even in the case of Urban feeders, where there are a much larger number of feeders and interruption events, the variation between years is over 16%.

The overall value of measures such as SAIDI and SAIFI is the result of a large number of relatively small, randomly distributed events (such as equipment failure, interference from animals, storms, wind, etc.). In an effort to understand gain some insight (albeit practical rather than statistically pure in approach) Evans & Peck has adopted the following approach:

- For each feeder type, the 3 years of daily SAIDI (and SAIFI) data are collected into 12 monthly data sets. Each data set has notionally 90 days data.
- A statistical distribution is fitted (using @RISK software) to each data set to establish 12 statistical functions which best describe the distribution of daily outcomes in each month of the year for each feeder type.
- These distributions are then used to construct a year, by applying the 12 distributions to the relevant number of days in each year.
- As the fitted distributions are continuous to infinity, some truncation rules are applied to either exclude values (which 2.5 Beta would define as exclusion events) or limit values to those observed in practice.
- A Monte carol simulation is then run to determine the range of outcomes over a large number of years (1000 in this case) for each feeder type.

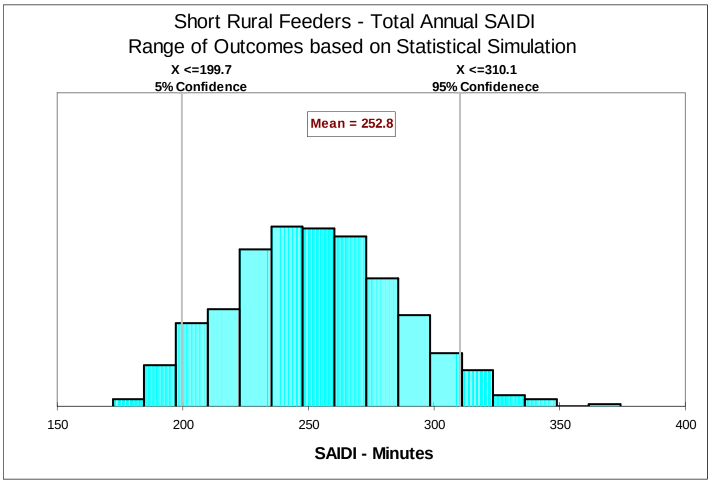
The results for Urban Feeders are presented graphically below:

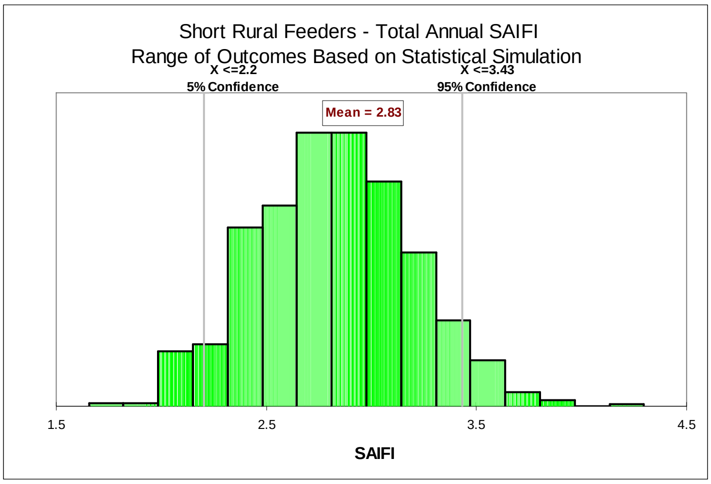




Based on this analysis, there is a 90% probability that Urban SAIDI will be in the range 65.9 to 82.6, but there is still a 5% probability of exceeding 82.6 minutes. Actual performance over the last 3 years has been within the statistical bounds expected, albeit at the lower end for both SAIDI and SAIFI in 2002/03. The implication of these statistical distributions is that if the status quo were maintained in terms of Urban Feeder reliability, the inherent variability will result in a range of annual outcomes. This range is considered in the context of licence compliance in the following sections.

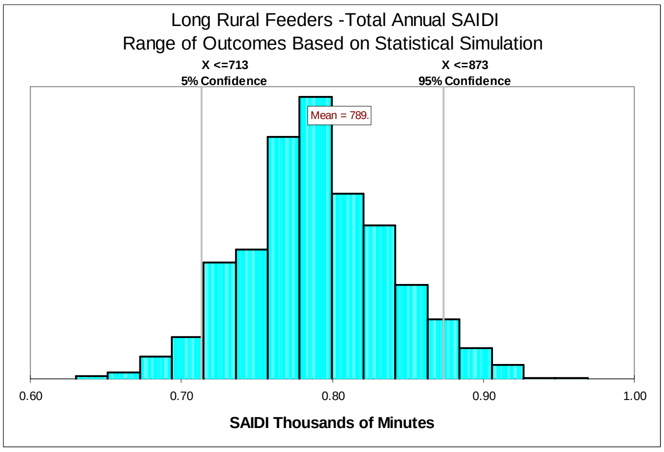
The results for Short rural Feeders are as follows:

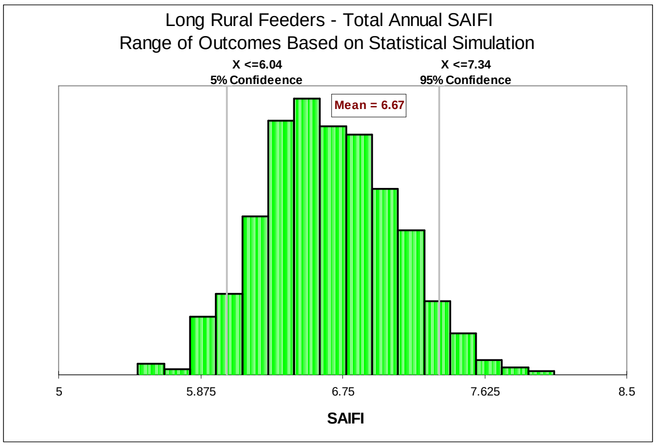




The actual performance of the Short Rural network over the past 3 years has, on occasions, been outside the 90% confidence interval for both SAIDI (343 minutes 2003 / 4) and SAIFI (3.65 in 2002 / 3 and 3.70 in 2003/4).

Modelling of Long Rural feeders is problematic due to the small number of feeders and the relatively discontinuous nature of both SAIDI and SAIFI events. Typically there are large numbers of days with zero SAIDI and SAIFI, interspersed with a series of highly variable days. Notwithstanding, we have applied the same methodology, and the results are shown below.





During the period 2002/3 to 2004/5 SAIDI ranged from 481 to 965, and SAIFI ranged from 5.01 to 8.71, both well outside the 90% confidence range of the respective models. The implication arising from this high degree of variability is that EnergyAustralia may need more programs in this sector than may have otherwise been the case to ensure continued compliance with the licensing conditions.

In essence, to ensure compliance the majority of years, EnergyAustralia needs to target average performance well below to compliance standard. In the case of Urban feeders, our initial recommendation would be 8-10% below, in case of Short Rural feeders approximately 15% below. and Long Rural feeders 10% lower. Put another way, if EnergyAustralia were to target their reliability compliance program to achieve average values specified in Schedule 2, they could expect to be non-compliant one year in two.

We have not performed this analysis on the CBD feeders. Failures in the CBD have been characterised by a small number of extremely high impact events that do not lend themselves to this type of analysis.

3.3 QUALITY OF RELIABILITY DATA

Evans & Peck is aware that many distribution authorities are in the process of implementing new information systems designed to more accurately track customer outage information. EnergyAustralia is no exception, and there is an internal awareness of the deficiencies in the current system. Whilst remedial action has been initiated, neither EnergyAustralia nor Evans & Peck are in a position to determine with accuracy the current level of under or over reporting of outage data. In July 2003, the Independent Pricing and Regulatory Tribunal (IPART) released a

"Review of NSW Distribution Network Service Providers Measurement and Reporting of Network Reliability"[2] prepared for IPART by PB Associates.

PB Identified that:

> *"Due to the fact that EnergyAustralia does not have readily identifiable records linking the customer to the network, either through the use of NMIs or any other method, EnergyAustralia has developed its own methodology by averaging the number of customers per distribution circuit based on the number of customers and distributors in a postcode area.*
>
> *This method can result in large errors in the computation of the reliability factors when considering areas smaller than the postcode area. The errors are such that when an overstatement occurs on one feeder, and understatement occurs on another. However, if particular performance figures are being targeted at a feeder level, this will remain a source of inaccuracy until an actual linkage is established between the customer and the network."*

PB concluded that there were deficiencies in EnergyAustralia's collection of reliability data and estimated that the overall reporting accuracy was + / - 10%. In its simplest interpretation, this implies an expected outcome of 0% error. Examination of the individual items contributing to the overall estimate (refer Table 6.1 page 62 of the PB Report) indicates that the actual result may be biased toward an increase in EnergyAustralia's values (i.e. current values understate the actual performance). Based on individual line items, the accuracy range appears to be –7.3 to + 13.5%, implying a mid point of 3.1% underestimate. However, PB Associates also identified that there are overlaps between line items, and simple addition is not valid.

Given that reliability performance is now a condition for licence compliance, Evans & Peck considers that, for the purposes of establishing initial reliability compliance programs, from a risk mitigation perspective it is reasonable for EnergyAustralia to assume that their overall reliability statistics will deteriorate by at least 5% as new reporting systems are implemented. We have therefore adjusted prior period results by this amount as the basis for establishing the need for reliability compliance programs based on average feeder performance.

3.4 INDIVIDUAL FEEDER PERFORMANCE

2 *http://www.ipart.nsw.gov.au/documents/ReviewofNSWDistributionNetworkServiceProvidersMeasurementandReportingofNetworkReliabilityPre.pdf*

Licence Compliance Conditions – Schedule 3 Individual Feeder Performance Standards		
Feeder Type	Annual SAIDI Minutes	Annual SAIFI
CBD	100	1.4
Urban	350	4
Short Rural	1000	8
Long Rural	1400	10

These requirements take effect from 1 October 2005, with the first reporting period ending on 30 September 2006.

In response to a request from Evans & Peck, EnergyAustralia has provided a list of individual feeders that did not meet this requirement in 2002/3, 2003/4 or 2004 / 5. In summary, the results are as follows:

Frequency of Non Compliance with Schedule 3 Individual Feeder Standards				
Times in Period 2002 /3 to 2004 / 5 Feeder Non Compliant	CBD	Urban	Short Rural	Long Rural
Once	15	108	20	0
Twice	0	19	3	1
Three Times	0	4	0	0
Total	15	131	23	1

Based on this information, EnergyAustralia will require reliability programs targeted at poorly performing feeders. In drawing this conclusion, we are cognisant of PB Associates comments in relation to the reliability of data pertaining to individual feeders. PB has suggested that the error attributable to individual feeders may be as high as 60%. We can only surmise that the current values are representative of the total number of feeders that will require attention to meet Schedule 3 requirements. We also note however that this set of feeders changes regularly. This implies that EnergyAustralia will need to target a larger set over a period of years as data collection improves, and the performance of individual feeders varies.

We have examined the role of both SAIDI and SAIFI as contributing factors to the non-compliance of these feeders. This is summarised below:

Causes of Non Compliance with Individual Feeder Standards				
Times in Period 2002 /3 to 2004 / 5 Feeder Non Compliant	CBD	Urban	Short Rural	Long Rural
SAIDI Only	12	24	7	1
SAIFI Only	0	45	11	
Both Measures	3	62	5	
Total	15	131	23	1

Of the 170 feeders in total in this list 123, or 72%, did not comply on the basis of SAIFI. This implies the need for programs that address the underlying reliability of the feeders, as well as those aimed at improving the response time to restore feeders.

3.5 IMPACT OF INDIVIDUAL FEEDER STANDARDS ON OVERALL RELIABILITY

Implementation of compliance strategies that address individual feeder standards will have an impact on overall feeder group reliability performance. In order to avoid duplication of programs, we requested EnergyAustralia to estimate the impact of bringing individual feeders to their compliance standard on overall group reliability.

The results are as follows:

Potential Improvement Resulting From Individual Feeder Improvement Program								
	CBD		Urban		Short Rural		Long Rural	
Year	SAIDI Minutes	SAIFI	SAIDI Minutes	SAIFI	SAIDI Minutes	SAIFI	SAIDI Minutes	SAIFI
2002/03	35.3	.01	11.4	.13	90.5	1.09	188.8	1.59
2003/04	93	.05	7.5	.11	24.6	.19	141	1.90
2004/05	2.3	.00	8.1	.11	0	0	254	.99
Estimate Applied to Simulation Model	N/A	N/A	10	.10	25	.2	150	1.0

Based on the assumption that EnergyAustralia can successfully implement an individual feeder standard compliance program that achieves the above outcomes, we have adjusted historic performance and our simulation model to reflect these improvements. The adjustments made to the simulation model based on broad estimates taking into account the extent to which the raw data fell outside the 90% confidence band.

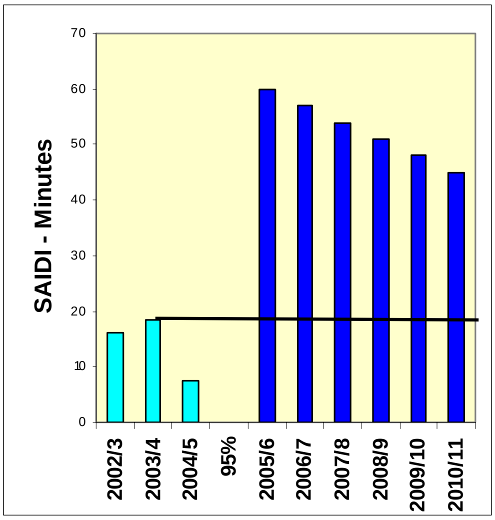
The Licence Compliance Conditions specify declining SAIDI and SAIFI compliance values over the period 2005/6 to 2010/11. These are tabulated below:

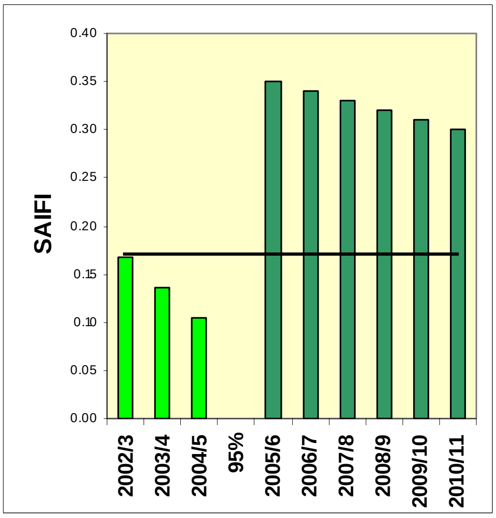
Licence Compliance Conditions – Schedule 2 Average Reliability Standards								
Year	CBD		Urban		Short Rural		Long Rural	
	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI
2005/06	60	.35	90	1.3	400	4.4	900	8.5
2006/07	57	.34	88	1.28	380	4.2	860	8
2007/08	54	.33	86	1.26	360	3.9	820	7.5
2008/09	51	.32	84	1.24	340	3.7	780	7
2009/10	48	.31	82	1.22	320	3.4	740	6.5
2010/11	45	.3	80	1.20	300	3.2	700	6

In order to assess the need for additional reliability compliance programs that target average feeder performance (in addition to individual feeder performance standards) we have compared theses values to the average values after adjustment for the impact of the individual feeder compliance programs. The comparisons are shown graphically below:

Feeder Group Performance after Adjustment for Individual Feeder Standard Compliance

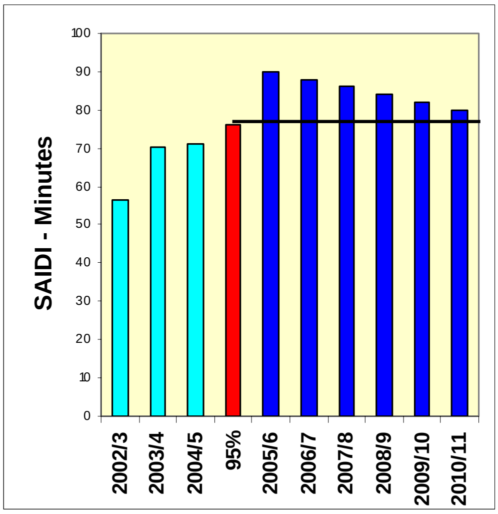
CBD[3] Feeders

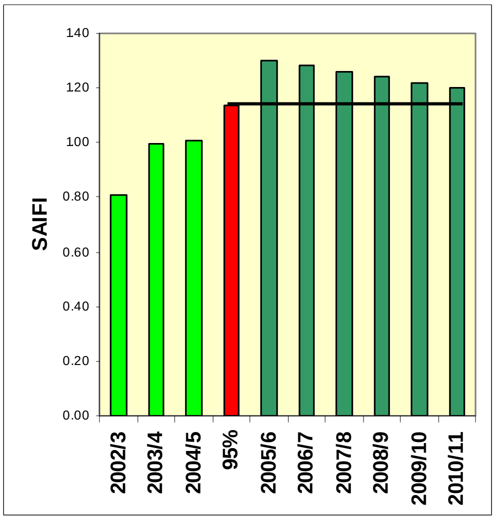




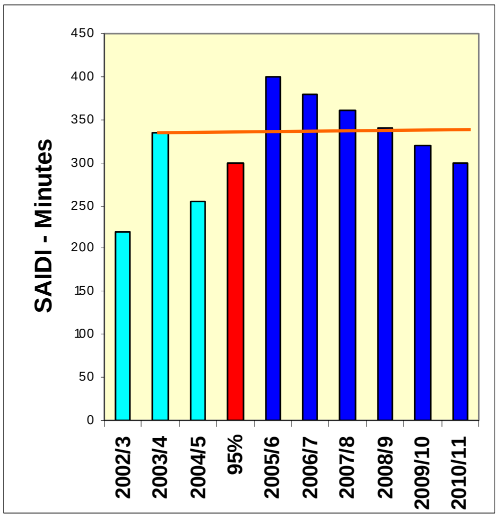
3 *We have not estimated the confidence interval for CBD feeders.*

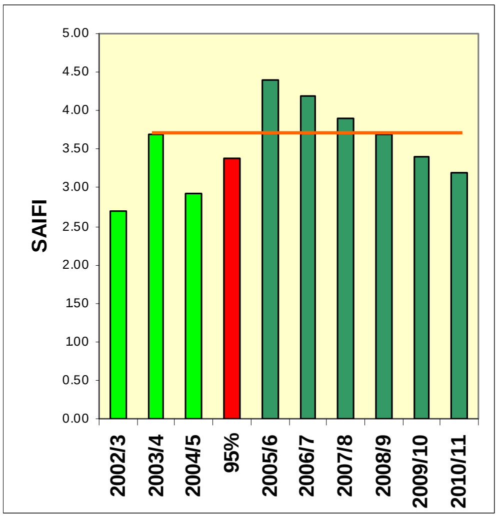
Urban Feeders



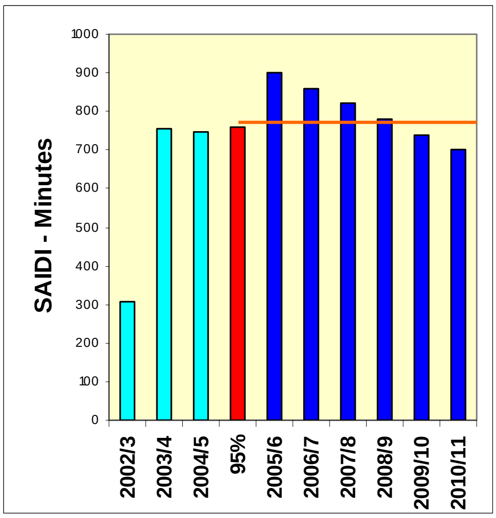


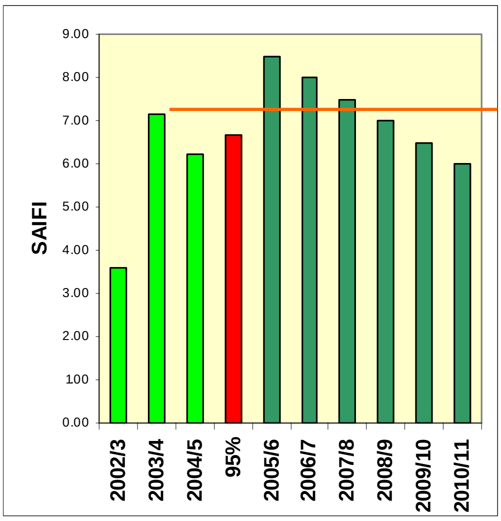
Short Rural Feeders





Long Rural Feeders





In order to assess the need for additional reliability compliance programs based on average feeder performance (over and above individual performance standards), we have drawn a reference line at the higher of:

- Historical performance adjusted for impact of individual feeder programs
- The 95% confidence interval derived in the simulation models adjusted for the impact of individual feeder performance programs (where applicable).

Visual inspection of the above graphs demonstrates that additional programs are required in the Short Rural and Long Rural feeder categories to achieve average compliance requirements. In order to keep ahead of the compliance requirement, these programs would need to commence no later than 2007 / 8.

In examining the performance of Urban feeders, Evans & Peck also notes that the Licence Compliance Conditions under Schedule 1 “Design Planning Criteria” requires EnergyAustralia to achieve N-1 (within 4 hours) capability on its Urban Feeder network by July 2009. This program should also result in a reduction in Urban feeder SAIDI (and possibly SAIFI). Based on the information currently at hand, Evans & Peck does not therefore believe a specific program is required to address the average performance of this group of feeders (over and above that applying to individual feeder standards).

Evans & Peck are of the view that programs in the CBD warrant special attention. A program centred on feeders that have performed poorly historically is unlikely to provide an effective mitigant against future non-compliances. Instead, Evans and Peck concurs with the view that any program needs to focus on identifying and mitigating risks in those installations, such as large jointing bays, where the failure of one cable could potentially result in the sequential failure of many cables. To this end, EnergyAustralia has proposed a capital program with an estimated capital requirement of $2million specifically targeted at reducing cascading failures in jointing bays at City South and Dalley St, and congested jointing pits.

3.6 ENERGYAUSTRALIA'S PROPOSED RELIABILITY PROGRAMS

As a result of the above analysis, Evans & Peck consider that a number of reliability compliance programs will be required to be implemented by EnergyAustralia during the current regulatory level. At the highest level, these requirements are summarised in the following table:

Reliability Compliance Programs Arising from Schedule 2 (Average) and Schedule 3 (Individual) of Licence Compliance Conditions

	CBD		Urban		Short Rural		Long Rural	
Year	Average Standard	Individual Standard	Average Standard	Individual Standard	Average Standard	Individual Standard	Average Standard	Individual Standard
2005/06	✘[4]	✘	✘	✓	✘	✓	✘	✓
2006/07	✘	✘	✘	✓	✘	✓	✘	✓
2007/08	✘	✘	✘	✓	✓	✓	✓	✓
2008/09	✘	✘	✘	✓	✓	✓	✓	✓

Following a series of discussions with EnergyAustralia representatives, Evans & Peck has tabulated the suite of generic programs that EnergyAustralia has indicated that they intend to implement in order to address reliability compliance issues at the high voltage feeder level. These are shown below.

[4] *Refer comments re need for risk mitigation strategy to limit spread of impact from individual feeder faults*

Generic Programs Proposed to Address Individual and Average Feeder Standards			
Program	Primary Target	Typical Elements of Program	Typical Works Arising as a Result of Program Implementation
Feeder Inspection and Thermovision Program	SAIFI Improvement – in Overhead Feeders	Visual inspection supplemented by thermovision scanning of poor performing feeders to identify potential defects.	• Accelerated Air Break Switch Repair / Replacement / Removal • Accelerated repair / replacement of bonds and links • Installation of spacers to prevent conductor clash in high wind • Accelerated replacement of surge arrestors
Distribution Automation Program	SAIFI and CAIDI	Installation of more advanced switches and circuit breakers on lines to permit more discrimination in switching and faster restoration times.	• Replacement of reclosers • Installation of additional reclosers • Installation of pole mounted switches to enable greater fault discrimination and speed restoration time • Installation of additional sectionalisers and auto links
Wildlife Proofing Program	SAIFI	Installation of insulating barriers on equipment with low insulation clearances to prevent wildlife initiated failure.	• Wildlife proofing of: o Underground / overhead connections o Pole transformers
Protection and Communication Program	SAIFI and CAIDI	Installation of signalling fault indicators and relays (telephone or visual) to speed fault location	Installation of: o Distance to fault relays o Telephone connected fault indicators o High power strobe earth fault indicators o Additional Instantaneous Overcurrent Protection to prevent conductor damage during faults
Conductor Program	SAIFI Improvement	Installation of covered conductor in heavily treed areas, overhead earthwire on sub transmission system to protect against lightning strikes	Installation of: o 11 kV Covered Conductor (CCT)(95CC) o Overhead Earth Wires on some sub transmission circuits o Covers on some high voltage mains.

These programs are typical of those currently being applied by other distribution service network providers across Australia to address reliability concerns. Applied in a targeted and cost effective way the programs are, in Evans & Peck's view, an appropriate response to the reliability compliance issues to be addressed. This list should not be considered exhaustive.

Following on from the above analysis, and the provision of data by EnergyAustralia on the number of feeders not meeting individual feeder standards, Evans & Peck has made a high level estimate of the number of feeders that will require application of some or all of these programs over the period 2005 / 06 to 2008 / 09.

As a result of changes in data collection techniques, and the variation from year to year of the feeders not meeting individual feeder standards, we would expect the number of number of urban feeders requiring attention to be significantly greater than those currently shown as not meeting individual standards. We have therefore estimated that 10% of feeders will require attention. This is a 25% increase on the number currently shown as not meeting individual standards.

A similar situation also exists in the case of Short Rural feeders. In addition, a supplementary program is required to address the average performance of this group. We have therefore estimated that approximately twice the number of feeders to those currently showing as not meeting individual standards will require attention.

In the case of Long Rural feeders, there are only 5 feeders. We have assumed that all of these feeders will be targeted for reliability improvement programs over the next 3 ½ years.

Our indicative feeder reliability compliance program is as follows:

Indicative Reliability Compliance Program					
Feeder Type	Total Number of Feeders	Average Length / Feeder	Number outside Individual standard	Estimated Number of Feeders to be Targeted in Reliability Compliance Programs	Average Length of longest 165/50/5 Feeders
Urban	1648	4.9 km	131	165	14.2 km
Short Rural	127	45.5 km	23	50	82km
Long Rural	5	273 km	1	5	273 km

In assessing the total length of line requiring attention, we have assumed that the sample requiring attention will be, on average, longer than the group as a whole. We have assumed that the average length of feeders requiring attention will be:

- In the case of Urban feeders – 11.4 km (80% of the average length of the longest 165 Urban feeders)
- In the case of Short Rural feeders – 65.6km (80% of the average length of the longest 50 Short Rural feeders)
- In the case of Long Rural Feeders – 273 km.

In order to develop an indicative capital and operational expenditure program, we have indicatively phased the work over a 3 ½ year period.

The resultant program is shown below.

Indicative Work Program								
	2005/6		2006/7		2007/8		2008/9	
	Number	Length km	Number	Length km	Number	Length km	Number	Length km
Urban	23	261	47	534	47	534	47	534
Short Rural	7	470	12	806	12	941	17	1142
Long Rural	1	273	2	546	2	546	1	273
TOTAL	31	1005	61	1886	61	2021	64	1949

3.7 OPERATIONAL AND CAPITAL EXPENDITURE REQUIRED TO IMPLEMENT PROGRAMS

Evans & Peck has worked in association with EnergyAustralia staff to translate these high level requirements on feeder numbers and feeder length. The personnel involved were responsible for, and experienced in, maintenance management programs. We have relied on their specific knowledge of the state of the assets, the number of assets that may require attention or installation, and the unit cost of that work. A list of expected work arising from each program was provided and is included as Attachment 2.

This program potentially results in an overall improvement in EnergyAustralia's SAIDI of approximately 10 –12 minutes per annum. The program requires a capital expenditure of approximately $120 million, with an annual operating expenditure of $5 million. If the capital is annualised at 10% pa, this equates to a total cost of $17 million per annum. With a customer base of 1.7 million, and a 10-minute SAIDI improvement, this translates to a broad indicator of $1.00 per customer per SAIDI minute per annum. This is not considered an unrealistic target.

4 PLANNING STANDARDS COMPLIANCE

4.1 LICENCE COMPLIANCE CONDITIONS

Schedule 1 of the Licence Conditions specifies the Design Planning Criteria now applicable to EnergyAustralia. An abridged version of this schedule, excluding those elements not applicable to EnergyAustralia, is presented in the following table.

ABRIDGED Design Planning Criteria				
Network Element	Load Type	Load Magnitude	From 1 July 2009 (all network elements) 1 July 2007 to 30 June 2009 (new network elements)	
			Security Standard	Customer Interruption Time
Sub Transmission Line	CBD[1]	Any	N-2	< 1 minute (1st outage); < 1 hour (2nd outage)
	Urban & Non-Urban	≥ 5 MVA	N-1	< 1 minute
	Non-Urban	< 5 MVA	N	*Best practice repair time*
Sub Transmission Substation	CBD[1,2]	Any	N-2	< 1 minute (1st outage); < 1 hour (2nd outage)
	Urban & Non-Urban[2]	Any	N-1	< 1 minute
Zone Substation	CBD[1, 2]	Any	N-2	< 1 minute (1st outage); < 1 hour (2nd outage)
	Urban & Non-Urban[2]	≥ 5 MVA	N-1	< 1 minute
	Non-Urban	< 5 MVA	N	*Best practice repair time*
Distribution Feeder	CBD[1, 4]	Any	N-1	< 1 minute
	Urban (town ≥ 15,000[3])[4]	Any	N-1	< 4 hours
	Urban (town ≥ 15,000[3])	Any	N	*Best practice repair time*
	Non-Urban	Any	N	*Best practice repair time*
Distribution Substation	CBD[1]	Any	N-1	< 1 minute
	Urban & Non-Urban	Any	N	*Best practice repair time*

1. CBD means the Sydney Central Business District only.
2. In any *financial year*, *load-at-risk* is permitted where the probability is <1% that load may not be able to be sustained following a failure. This applies except:
   (a) For sub-transmission and Sydney CBD zone substations, all *load-at-risk* must be eliminated from June 30 2012;
   (b) For all other zone substations ≥20MVA, all *load-at-risk* must be eliminated within the next two *regulatory periods* following the present *regulatory period.*
3. This standard does not apply to interim supplies to developments prior to completion of the development. The timeframe is expected based on the needs to carry out 3-5 manual field switching operations and does not apply in cases of numerous coincident outages (e.g. during major storms), traffic gridlock or other factors outside the control of the electricity distributor.
4. The actual security standard is an enhanced N-1. For a second distribution feeder loss in the CBD, restricted essential load can still be supplied (approximately 50% of peak load, percentage of load at time of outage is dependent on time of year and daily load cycle).

4.2 IMPLICATIONS ARISING FROM DESIGN PLANNING CRITERIA -

As a general rule, EnergyAustralia has adopted a deterministic N-1 planning policy in relation to its Sub-transmission Substations and CBD Zone Substations. A probabilistic approach has been applied to other Zone Substations, but in some cases load at risk exceeds 1%. Much of the urban 11kV network has been designed on the basis of an open ring configuration. However, this policy has not been exclusively applied nor has capacity always been reserved in feeders to allow load pickup of adjoining feeders in the case of outages. As a general rule, the Planning Design Criteria applicable to distribution substations is consistent with EnergyAustralia's preferred construction.

The main implications for EnergyAustralia arising from the need to comply with the design planning criteria are therefore:

- The need to move to N-2 in the CBD on Sub-transmission Lines and Zone Substations.
- The need to reduce load at risk to less than 1% at zone substations (with load in excess of 5MVA) as an issue of licence compliance.
- The need to establish N-1 (<4 hour restoration) across all Urban 11kV Feeders

The Design Planning Criteria include reference to a number of key dates. These include:

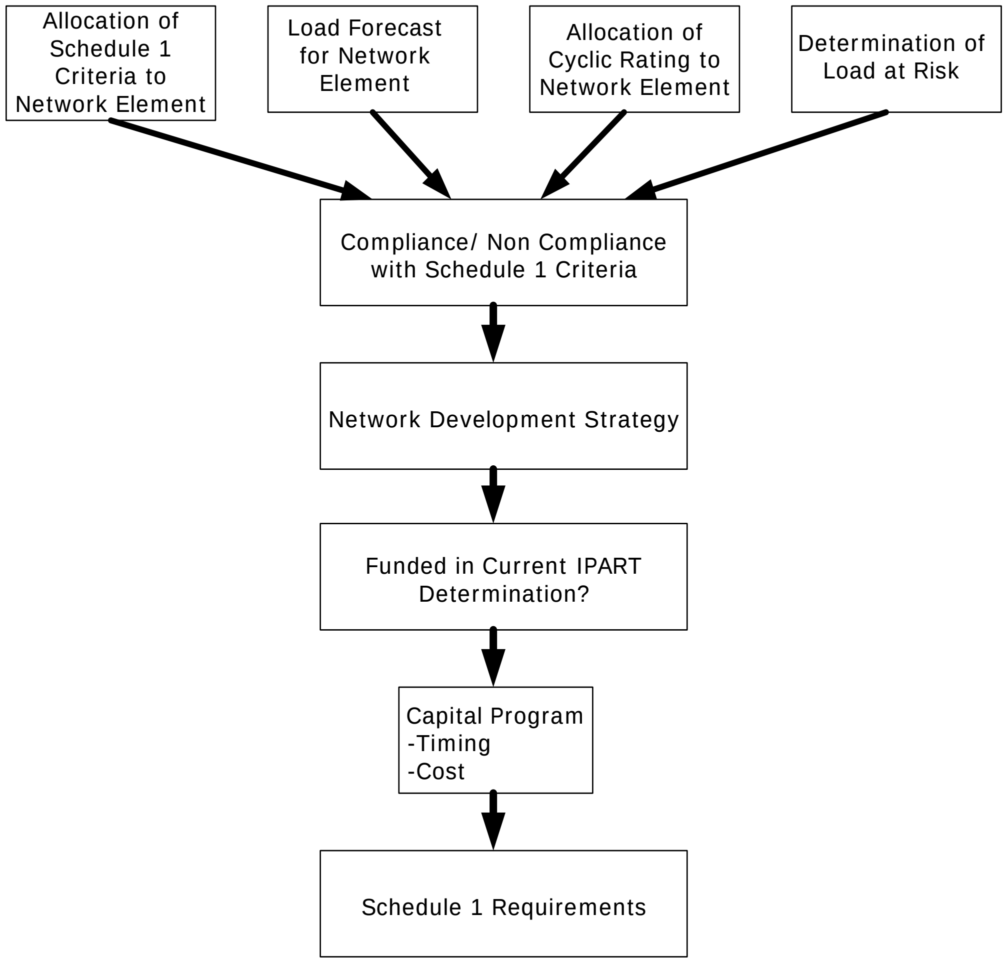
- New network elements to comply by 1 July 2007
- Existing network elements to comply by 1 July 2009 subject to:
    - 1% load at risk in the event of a failure being permitted until 30 June 2012 in the case of sub-transmission substations and CBD zone substations.
    - 1% load at risk in the event of equipment failure being acceptable on other zone substations with greater than 20MVA load for two regulatory periods after the end of the current period (potentially 30 June 2019)
    - by deduction, 1% load at risk in the event of equipment failure being acceptable on zone substations less that 20MVA indefinitely.

In completing this review, we have primarily focussed on the initial criteria, rather than the longer-term criteria.

4.3 IDENTIFICATION OF SUB-TRANSMISSION LINES, SUB-TRANSMISSION SUBSTATION AND ZONE SUBSTATION PROJECTS

In examining EnergyAustralia's proposed Design Planning Criteria program, Evans & Peck has reviewed the process that EnergyAustralia has adopted in establishing projects for inclusion in the 2005 / 6 – 2008 / 9 compliance program.

For Sub-transmission Lines, Sub Transmission Substations and Zone Substations this can be summarised as follows.



Evans & Peck has not reviewed every element of this process. However, we make the following high-level observations:

- EnergyAustralia has a well-developed plant rating policy, which develops ratings for major Network Elements recognising the specific design of the equipment, and the application that it is serving.

- EnergyAustralia has targeted their capital program on the basis of the initial (2007 and 2009) requirements rather than the ultimate requirements. This is considered prudent in the context of the forthcoming review of the licence compliance conditions.

- EnergyAustralia appear to be basing their analysis on recent load forecasts and recent load flow studies. Forecasts are generally based on a 50% probability of exceedance weather pattern. This potentially understates the level of load at risk in individual years.

- Loadings on network elements are 'normalised' to remove artificially high loads such as those arising from emergency switching arrangements.

- Determination of load at risk utilises load profiles specific to each network element, normalises these to forecast maximum demand specific to that element, and calculates load at risk based on both the time that load exceeds firm rating and the assigned probability of equipment failure. We have not reviewed these parameters at a detailed level. EnergyAustralia base their analysis on seasonal load at risk, based on a 4 month winter period and a 4-month summer period.

- We have reviewed the summary output of this process, and converted the load at risk to represent an annual value. The set of proposed projects for the period 2005/6 to 2008/9 correlates highly with those network elements with calculated load at risk rising to in excess of 1% over the period 2005/6 to 2008/9. Where exceptions are evident, we have sought additional confirmation of the reason for inclusion, or asked EnergyAustralia to reconsider the project. In a number of cases, projects have subsequently been removed.

- There is a diversity of solutions proposed, including 11kV load transfers, additional transformers and recognition of the impact of related projects (such as a new neighbouring substation).

- Whilst some projects do not appear to be justified on a stand alone basis, they are usually proposed as solutions to resolving issues in neighbouring network assets (for example, 11kV transfers from adjacent Zone Substation may necessitate the installation of an additional transformer).

- Those projects that were funded under the current IPART Determination have been identified, and to the best of our knowledge, eliminated.

- We have not independently assessed the capital cost assigned to each project (other than to examine the broad "reasonableness" of the values).

- EnergyAustralia operates under two regulatory jurisdictions. The ACCC has issued a determination in relation to Transmission Assets, and IPART has issued a determination in relation to distribution assets. Expenditure requirements have been split accordingly.

The resultant program of proposed works arising from Schedule 1 Licence Compliance Conditions pertaining to Sub-transmission Feeders, Sub-transmission Substations and Zone Substations is included as Attachment 1 to this report.

4.4 IDENTIFICATION OF DISTRIBUTION FEEDER PROJECTS

EnergyAustralia has approximately 1650 Urban and 130 Short Rural Distribution Feeders. Evans & Peck anticipate almost all Urban Feeders, and a number of Short Rural Feeders will be impacted by the Licence Compliance Design Criteria requiring 4 hour "N-1" restoration capability on Distribution Feeders serving urban areas (including towns with a population greater than 15,000).

Significant portions of EnergyAustralia's network incorporate an "open ring" design. This is not unilateral. Whilst providing a framework for the implementation of these criteria, capacity must also be reserved in feeders in order to enable the transfer of load between feeders.

In assessing the implications of this compliance requirement, EnergyAustralia has, at least initially, adopted a "5 into 4" concept. This implies that the load from a faulted distribution feeder can be transferred, by switching, to four other feeders. In Evans & Peck's view, "5 into 4" represents a reasonable practical compromise. "6 into 5" is unlikely to achieve switching in the required time, and "4 into 3" would require additional capital, and importantly, additional construction resources.

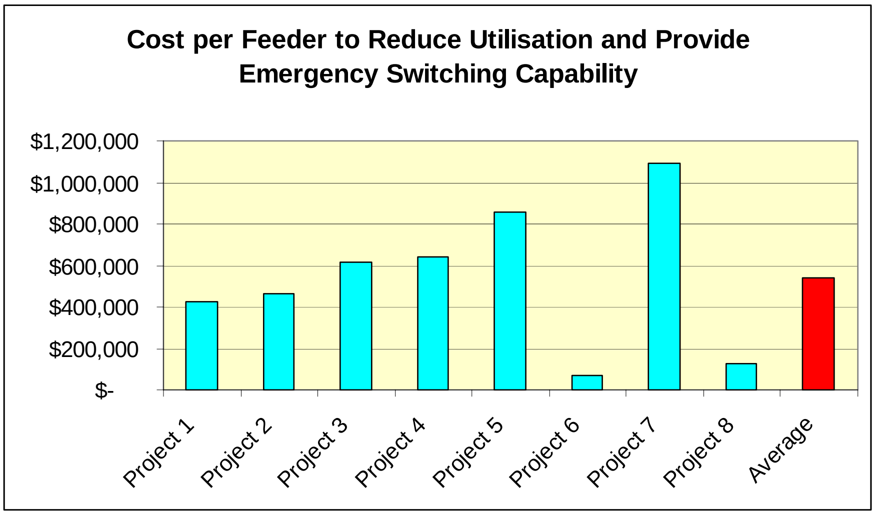
The key implication of a "5 into 4" planning policy is that the normal load utilisation of the majority of feeders must be reduced below 80%.

The estimation of capital expenditure required to meet this compliance requirement is difficult, particularly in the short time frame available. Evans & Peck has reviewed the high level methodology adopted by EnergyAustralia.

EnergyAustralia has provided information on 360 feeders where 2005 /6 forecast load currently exceeds 80% of assigned rating in summer, winter or both summer and winter. In addition, they have estimated that an additional 30 feeders per annum encroach this threshold due to load growth.

In order to assess the likely capital cost of this compliance program, Evans & Peck reviewed the internal project approvals for a total 8 recent projects that were presented by EnergyAustralia as "representative" of projects with a stated objective of relieving existing feeder constraints and enhancing emergency switching capability.

In one case, Evans & Peck significantly reduced the capital attributable to the project on the basis that also served significant new loads. In another case, we have increased the number of feeders impacted over the values originally supplied by EnergyAustralia. In some cases, the projects resolved loading issues on a number of feeders. On this basis, a "cost per feeder" was calculated. The resultant values are graphed below:



Costs per feeder vary considerably. The average value is approximately $537,000 per feeder. At this stage, we would ascribe the term 'indicative' to these calculations.

Compliance with this licence condition is required by July 2009. The analysis above suggests that some 480 projects will be required over that period. Based on this a proportionate phasing of projects over the period, we have estimated the capital requirements as follows.

Schedule 1 Distribution Feeder N-1 (4 hour) Compliance Program				
	2005 / 06	2006 / 07	2007 / 08	2008 /08
Existing Feeder Projects	60	100	100	100
"Growth Feeder" Projects		40	40	40
Total Projects	60	140	140	140
Capital cost @ $537,000 / project	$32.2 million	$75.2 million	$75.2 million	$75.2 million

EnergyAustralia has used a value of $600,000 per feeder in their estimate of the cost of this program. They have also presented an argument that, to some extent, the projects completed to date may be simpler projects at the lower end of the cost range.

At this early stage of analysis, Evans & Peck are not in a position to dispute the use of $600,000 per feeder as a reasonable basis for a high level estimate of the cost of this compliance program. We also note that EnergyAustralia has recognised that some allowance exists in the current Determination for this type of work, and have reduced additional requirements accordingly.

ATTACHMENT 1A SCHEDULE 1– DESIGN PLANNING CRITERIA PROJECTS – IPART DETERMINATION

Region	Asset Type	Project	Criteria
Sydney	Subtran Line	Haymarket -City North 132kV	Schedule 1 N-2
Sydney	Subtran Line	Erina - Avoca 66kV	Schedule 1 N-1
Hunter	Subtrans Line	Glebe - Merewether 960 132kV	Schedule 1 N-1
Hunter	Subtrans Line	Glebe - Merewether 961 132kV	Schedule 1 N-1
Hunter	Subtrans Line	Tomago - Williamtown 10 33kV	Schedule 1 N-1
Hunter	Subtrans Line	Tomago - Williamtown 7 33kV	Schedule 1 N-1
Hunter	Subtrans Line	Denman - Merriwa 33kV Upgrades	Schedule 1 N-1
Hunter	Subtrans Line	Kurri to Cessnock 33kV	Schedule 1 N-1
Sydney	Zone Substation	City North 5th Transformer	Schedule 1 N-2
Sydney	Zone Substation	Site for City East	Schedule 1 N-2
Sydney	Zone Substation	Design and part construction City East	Schedule 1 N-2
Sydney	Zone Substation	CBD 11kV interconnectors	Schedule 1 N-2
Hunter	Zone Substation	Broadmeadow Upgrade, 11kV transfers	Schedule 1 N-1
Hunter	Zone Substation	Cardiff 11 kV Transfers	Schedule 1 N-1
Hunter	Zone Substation	Charlestown 11kV Transfers, rebuild	Schedule 1 N-1
Hunter	Zone Substation	East Maitland 11kV Transfers, Rebuild	Schedule 1 N-1
Hunter	Zone Substation	Edgeworth - West Wallsend Zone Construction*	Schedule 1 N-1
Hunter	Zone Substation	Swansea Transformer Upgrade	Schedule 1 N-1
Hunter	Zone Substation	Toronto - new Rathmines Zone sub*	Schedule 1 N-1
Sydney	Zone Substation	Arncliffe - 11kV Transfers	Schedule 1 N-1
Sydney	Zone Substation	Avoca - Additional Transformer	Schedule 1 N-1
Sydney	Zone Substation	Blakehurst - 11kV Transfers	Schedule 1 N-1
Sydney	Zone Substation	Caringbah 11kV transfers	Schedule 1 N-1
Sydney	Zone Substation	Concord Additional Transformer	Schedule 1 N-1
Sydney	Zone Substation	Cronulla 3rd Transformer	Schedule 1 N-1
Sydney	Zone Substation	Double Bay 4th Transformer	Schedule 1 N-1
Sydney	Zone Substation	Greenacre Park to Sefton I&E switch replacement with CBs	Schedule 1 N-1
Sydney	Zone Substation	Greenacre Park 11 kV transders to Sefton	Schedule 1 N-1
Sydney	Zone Substation	Hurstville North Capacitors and 11kV Transfers	Schedule 1 N-1
Sydney	Zone Substation	Jannali - 11kV Transfers	Schedule 1 N-1
Sydney	Zone Substation	Kurnell new substation	Schedule 1 N-1
Sydney	Zone Substation	Lake Munmorah 132kV conversion	Schedule 1 N-1
Sydney	Zone Substation	Miranda 11kV Transfers	Schedule 1 N-1
Sydney	Zone Substation	Mosman and Castle Cove I&E switch replacement with CBs	Schedule 1 N-1
Sydney	Zone Substation	Pymble increase transformer rating	Schedule 1 N-1
Sydney	Zone Substation	Revesby - 3rd Transformer	Schedule 1 N-1
Sydney	Zone Substation	Rose Bay - 11 kV transfers to Waverly	Schedule 1 N-1
Sydney	Zone Substation	Turramurra - 11kV Transfers	Schedule 1 N-1
Sydney	Zone Substation	Umina - 3rd Transformer	Schedule 1 N-1
Hunter	Zone Substation	Merriwa	Schedule 1 N (Best Practice)
	Distribution Feeders	Reduce Feeder utilisation to 80% to allow 5 into 4 switching	Schedule 1 N-1

ATTACHMENT 1B SCHEDULE 1 – DESIGN PLANNING CRITERIA –ACCC DETERMINATION

Sydney	Subtran Line	Hunters Hill 90J 132kV	Schedule 1 N-1
Sydney	Subtran Line	Vales Pt - Lake Munmorah 132kV	Schedule 1 N-1
Sydney	Subtran Line	Munmorah - Lake Munmorah 132kV	Schedule 1 N-1
Hunter	Subtrans Line	Newcastle - Beresfield 9NA 132kV Upgrade	Schedule 1 N-1
Sydney	Subtrans Substation	Design and part construct Surry Hills busbar	Schedule 1 N-2
Hunter	Subtrans Substation	Kurri Reconstruction (Note 50% replacement)	Schedule 1 N-1

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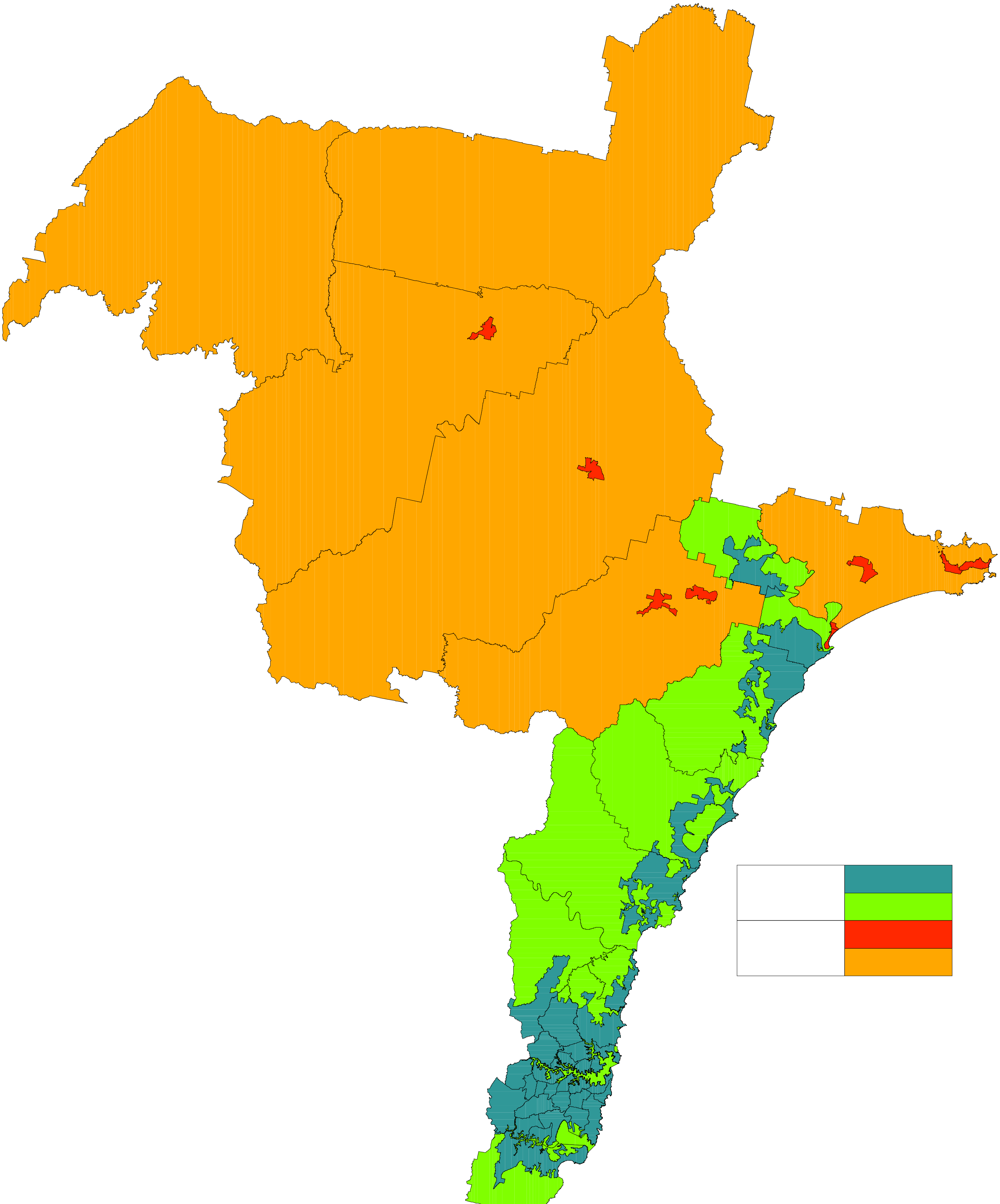
ATTACHMENT 2 RELIABILITY STANDARDS – SCHEDULE-2 (AVERAGE) AND SCHEDULE-3 (INDIVIDUAL) PROGRAM REQUIREMENTS

Program			Unit	Comments	Units - Opex				Units - Capex			
					2005/6	2006/7	2007/8	2008/9	2005/6	2006/7	2007/8	2008/9
Feeder Inspection and Thermovision Program			Feeder kms		1000	2000	2000	2000				
	Works Arising	ABS Repair incl U Bolt	unit		100	200	200	200				
		ABS Replacement	unit						250	500	500	500
		ABS Removal	unit	Bonded Through	250	500	500	500				
		Under Slung Link Replacement	unit	Like for Like	10	20	20	20				
		Bond Repair	unit		150	300	300	300				
		Surge Divertor replacement	unit	per set	300	600	600	600				
		11kV spacers	unit	Live Line	25	50	50	50				
		lv spacers	unit									
Distribution Automation Program			Feeders									
	Works Arising	Recloser Replacement	unit						10	25	25	25
		New Reclosers	unit						25	60	70	80
		New Pole Mounted Switch	unit	With Comms					5	30	50	70
		New Sectionalisers / Autolinks							25	60	70	80
Wildlife Proofing Program			Feeders									
	Works Arising	UGOH's		Incl. Arrestors	25	60	70	80				
		Pole Transformer			10	30	40	50				
Protection and Communication Program			Feeders									
	Works Arising	Distance to Fault relays	unit						5	15	20	20
		IOC Relays	unit						5	15	20	20
		Type 5 EFI	unit						50	200	500	1000
		Line Fault Indicators	unit	Indicator Only					50	200	500	1000
Conductor Program			Feeders									
	Works Arising	CCT	km						10	40	40	20
		95CC	km						0	40	80	100
		OHEW (Subtrans only)	km						50	100	100	100
		HV Mains Covers	km						0	40	80	100
CBD Containment Program									0.1	0.3	0.3	0.3

Attachment 3: Map of EnergyAustralia's Urban and Rural Network Areas



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