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Network Determination Application for General Pass Through and Specific Pass Through

to the

Independent Pricing and Regulatory Tribunal

2 December 2005

Contents

1 Overview

1.1 Summary

The Tribunal regulates the prices of Distribution Network Service Providers (DNSPs). The Tribunal's 2004 Network Determination (Determination) sets out cost pass through mechanisms for certain events that could occur during the 2004-09 regulatory period and could affect the DNSPs' costs, but had not been allowed for in prices set through the Determination.

The Tribunal's NSW Electricity Distribution Pricing, 2004/05 to 2008/09, Final Report (Final Report) and Determination distinguish between specified events and other circumstances where there is a change in a taxation or regulatory obligation. The approach to decisions about pass through of costs associated with general events is set out in the General Cost Pass Through Mechanism. Decisions about pass through of costs associated with specified events are set out in the Specific Cost Pass Through Mechanism.

On 1 August 2005, the Minister for Energy and Utilities imposed additional licence conditions on Integral in the form of new design, reliability and performance standards.

Integral Energy (Integral) considers that imposition of some of the new licence conditions[1] is a Pass Through Event under Clause 14 of the Determination. Integral is seeking the Tribunal's approval to pass through the costs resulting from this event under Clause 14 of the Determination.

In addition, Integral believes that imposition of the Customer Service Standards (CSS) by the new licence conditions is a Specific Pass Through Event under the terms of the Determination[2]. Therefore, Integral is seeking the Tribunal's approval to pass through costs resulting from this event under Clause 15 of the Determination.

This submission includes Integral's separate Applications for a General Cost Pass Through and a Specific Cost Pass Through. The proposed pass through amounts are set out in Table 1.1 following.

[1] Notably, the new design planning criteria, the new reliability standards, the new individual feeder standards and the new performance monitoring and reporting requirements associated with these new criteria and standards.

[2] The Final Report included "possible introduction of additional expected payments linked to Guarantee Customer Service Standards as a result of the Tribunal's recommendations to the Minister for Energy and Utilities to introduce payments linked to network reliability" as a specified event.

2004/05$ million	2004/05	2005/06	2006/07	2007/08	2008/09	Total
General Cost Pass Through Event						
Incremental capital expenditure	(40.59)	3.40	89.07	93.51	200.97	346.36
Proposed Positive Pass Through Amount (Revenue requirement nominal $ million)	**-**	**-**	**5.00**	**10.00**	**20.15**	**35.15**
Specific Cost Pass Through Event						
Incremental capital expenditure	-	-	0.46	-	-	0.46
Incremental operating expenditure	-	0.34	1.76	1.74	1.74	5.58
Proposed Specific Pass Through Amount (Revenue requirement nominal $ million)	**-**	**-**	**1.50**	**2.50**	**2.27**	**6.27**

Table 1.1 – General Cost Pass Through and Specific Cost Pass Through of costs to network tariffs - proposed Positive Pass Through Amounts and Specific Pass Through Amounts resulting from new customer service standards

The negative increment in 2004/05 for the capital expenditure associated with the General Cost Pass Through Event reflects the difference in the profile of expenditure between the Determination allowance and Integral's capital delivery plan to expend the same total approved allocation over the regulatory period.

Integral seeks approval by the Tribunal under sections 14.2(b) and 15.2(b) of the Determination to pass through its proposed Positive Pass Through Amount and Specific Pass Through Amount respectively.

In applying to pass these amounts through to Distribution Customers in network tariffs, Integral has considered the costs resulting from the pass through events, the tight timeframe for compliance with the new licence conditions and the impact on customers of increasing network tariffs. The timeframe for implementing projects to meet the new licence conditions will require Integral to address a number of challenges associated with project delivery. Integral currently operates within an environment of full employment, a growing economy, equipment suppliers reaching their maximum output capability, and critical skill shortages.

Integral would like to work with the Tribunal to identify options to provide for a “true-up” mechanism within the regulatory framework whereby the actual costs associated with the General and Specific Cost Pass Through Events are retrospectively passed through to customers. Integral’s preliminary view is that the current regulatory framework may allow such a mechanism provided that the mechanism was formulaic. However, Integral recognises the challenge in developing such a mechanism within the current regulatory framework.

Integral’s analysis indicates that the pass through will increase the X factor from -1.5% to -2.7 % per annum over the period 1 July 2006 to 30 June 2009. This increase in the X factor translates to an increase of approximately $5 each year above the existing Determination for the typical domestic customer (with an annual consumption of 7.5 MWh), or a cumulative increase of $30 over the three years remaining in the regulatory period. The annual increase is approximately 0.5 percent of the total electricity cost for a domestic customer.

For an average general supply customer (with an annual consumption of 20 MWh), the annual increase is estimated to be around $11 above the existing Determination, or a cumulative increase of $66 the three years remaining in the regulatory period. This annual increase is less than 0.5 percent of the total electricity cost for that customer.

Table 1.1 below summarises Integral’s analysis of the impact of the proposed pass through amounts on residential and business customers’ bills.

Customer type and annual consumption, nominal $	Estimated Distribution bill (2006/07) – Before licence conditions	Estimated Distribution bill (2006/07) – After licence conditions	Additional annual cost	Estimated percentage of total retail bill
Residential				
Low usage (3.5MWh)	**$249**	**$252**	**$3**	**0.5%**
Typical usage (7.5MWh)	**$453**	**$458**	**$5**	**0.5%**
High usage (10MWh)	**$592**	**$599**	**$7**	**0.5%**
Business				
20MWh (Typical usage)	**$911**	**$922**	**$11**	**0.4%**
40MWh	**$1,829**	**$1,850**	**$21**	**0.4%**
80MWh	**$3,674**	**$3,716**	**$42**	**0.4%**

Table 1.1 – Analysis of customer impacts

1.2 Structure of submission

The submission is structured as follows:

Section	Title	Details
2	Background and context	Summarises the relevant cost pass through provisions in the Determination. Provides an overview of the new licence conditions, and explains how these conditions include both a Positive Change Event and a Specific Pass Through Event as defined in the Determination.
3	General Cost Pass Through Application	Sets out Integral's application for pass through of costs to network tariffs consistent with clause 14.2 of the Determination.
4	Specific Cost Pass Through Application	Sets out Integral's application for pass through of costs to network tariffs consistent with clause 15.2 of the Determination.
5	Customer Outcomes	Summarises Integral's analysis of the overall impact of the cost pass through applications on customers.
Appendix	**Title**	**Details**
A	Glossary	Defines commonly used terms and references throughout this document.
B	PB Associates report	"New Network Licence Conditions – Impact Assessment", 10 November 2005

Note numbers contained in tables of this application may differ slightly due to rounding.

2 Background and context

2.1 Summary of pass through provisions in the 2004 Determination

The Determination includes provisions for Integral to apply to the Tribunal to pass through amounts associated with General Pass Through events and Specific Pass Through events.

A General Pass Through[3] event is defined as "a Regulatory Change Event or a Tax Change Event."

A Regulatory Change Event[4] 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.

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[3] As defined in Annexure 1 of the NSW Electricity Distribution Pricing 2004/05 to 2008/09 Determination No 2, 2004.

[4] Ibid.

A Specific Pass Through Event[5] *means any of the following events where they occur on or after 1 July 2004:*

(1) …

(2) …

(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 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 Determination requires that the Tribunal make its decision on any cost pass through application "not later than 80 Working Days prior to the beginning of each Year[6]." Integral understands that given the timing of the cost pass through events, the Tribunal is concerned about its ability to complete its due process review by 80 working days prior to 1 July 2006. Consequently, the Tribunal has had discussions with the DNSPs about relaxing the 80 working day timeframe.

Integral is prepared to relax the 80 working day timeframe provided that price increases can still be effected and passed through to retail customers in the 2006/07 financial year. Integral notes that retail price increases must be made within 14 days of 1 July 2006[7]. In addition, in relaxing the time constraints Integral needs to understand how the Tribunal's decision on the cost pass through applications would be factored into the Annual Pricing Proposal which Integral must submit to the Tribunal by the first Monday[8] in April 2006 (3 April 2006).

2.2 The new licence conditions

On 1 August 2005 the Minister for Energy and Utilities imposed additional licence conditions on Integral. These additional licence conditions entitled "Design, Reliability and Performance Licence Conditions" impose planning, reliability and performance standards and require Integral to comply with these standards over certain timeframes.

[5] ibid.

[6] Clauses 14.5(b) and 15.4(b) of the NSW Electricity Distribution Pricing 2004/05 to 2008/09 Determination No 2, 2004.

[7] Clause 5.1 of the NSW Electricity Regulated Retail Tariffs 2004/05 to 2006/07 Determination No1, 2004

[8] Clause 12.5 of the NSW Electricity Distribution Pricing 2004/05 to 2008/09 Determination No 2, 2004

PB Associates were engaged to independently review Integral's assessment of the network system capital costs. PB Associates' report[9] is provided in Appendix B. In section 2.1 of its report, PB Associates sets out the specific requirements of the new licence conditions that are relevant to Integral's distribution network areas. In section 2.2 of its report, PB Associates compares Integral's existing policies, standards and performance with those of the new licence conditions to identify the impact on Integral's present and forecast network performance.

The new licence conditions also impose a requirement for Integral to pay customers for failure to meet specified reliability performance standards (the Customer Service Standards).

2.3 Review of new licence conditions

The new licence conditions require a review within two years of the effectiveness of the design, reliability and performance conditions in facilitating the delivery of a reliable supply of electricity at reasonable cost. The Department of Energy, Utilities and Sustainability (DEUS) has released a terms of reference to set up the Reliability Standards Review Committee to undertake the review. Integral understands that DEUS intends to complete its review by June 2006.

Integral recognises that the findings of the Committee may impact future licence conditions, costs and cost pass through amounts. However, in compiling this cost pass through application, Integral has assumed that the Committee's decisions will not affect the new licence conditions.

2.4 Annual adjustment mechanism

Integral would like to explore with the Tribunal, whether there are any options to provide for a "true-up" mechanism within the regulatory framework whereby the actual costs associated with the General and Specific Cost Pass Through Events are retrospectively passed through to customers. Integral's preliminary view is that the current regulatory framework may allow such a mechanism provided that the mechanism was formulaic.

Integral believes that a mechanism for the Specific Pass Through Events is relatively straight forward given that the customer service standard payments in the new licence conditions are $80 per defined event.

However, for the General Pass Through Events, Integral recognises the challenge in developing such a mechanism when dealing with capital expenditure where decisions need to be made about efficient level of that expenditure associated with specific projects. In addition, the mechanism would only work if it was self-executing, not requiring the Tribunal's decision on component parts.

[9] PB Associates – "New Network Licence Conditions – Impact Assessment", 10 November 2005.

2.5 The Tribunal's 2004 Determination Allowances

In its Determination[10], the Tribunal made the following allowances for capital and operating expenditure over the 2004 regulatory period:

Nominal $ million	2004/05	2005/06	2006/07	2007/08	2008/09	Total
Capital expenditure						
System	240.40	273.40	258.00	266.50	230.50	1268.80
Non-system	44.80	30.40	23.60	24.30	27.50	150.60
Total capital expenditure	285.20	303.80	281.60	290.80	258.00	1419.40
Operating expenditure	208.30	213.70	221.20	228.80	236.40	1108.40
2004/05 $ million						
Capital expenditure						
System	240.40	266.73	245.57	247.47	208.82	1208.99
Non-system	44.80	29.66	22.46	22.56	24.91	144.40
Total capital expenditure	285.20	296.39	268.03	270.04	233.74	1353.39
Operating expenditure	208.30	208.49	210.54	212.46	214.17	1053.96

Table 2.1 – Determination capital and operating expenditure allowances

In making these cost pass through applications, Integral has determined the incremental costs associated with the pass through events in relation to the Tribunal's Determination allowances set out above.

In the case of system capital expenditure, because Integral's capital planning aggregates the capital associated with streetlighting, to ensure a "like with like" comparison, Integral has added an allowance for streetlighting capital to the system capital expenditure allowances set out above. The resulting "baseline" Tribunal Determination capital expenditure is shown in Table 2.2.

[10] Refer section A12.8 table A12.13 of the Determination for capital expenditure allowances and section A12.0 table A12.9 for operating expenditure allowances.

2004/05 $ million						
Capital expenditure						
Tribunal System	240.40	266.73	245.57	247.47	208.82	1208.99
Streetlighting	2.99	2.99	2.99	2.99	2.99	14.95
Total baseline "Tribunal" determination capital expenditure	243.39	269.72	248.56	250.46	211.81	1223.94

Table 2.2 – Calculation of "baseline" Tribunal Determination capital expenditure

3 General Cost Pass Through

3.1 Summary

Under Clause 14 of the Determination, Integral must give the Tribunal a written statement and accompanying evidence to support the Determination.

This Chapter addresses the requirements of that statement as set out in Clause 14.2 (a) as follows:

Section 14.2 Requirements		Integral Application Reference
(1)	the details of the Positive Change Event concerned;	Section 3.2
(2)	the date the Positive Change Event occurred;	Section 3.2
(3)	the increase in costs in the provision of Passthrough 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 Positive Change Event (ie the Eligible Pass Through Amount (as calculated by the DNSP) in respect of that Positive Change Event);	Section 3.3
(4)	the Positive Pass Through Amount the DNSP proposes in relation to the Positive Change Event;	Section 3.4
(5)	the amount of that Positive Pass Through Amount that the DNSP proposes should be passed through to Distribution Customers in each Year during the Regulatory Control Period;	Section 3.4
(6)	evidence of the actual and likely increase in costs referred to in clause 14.2(a)(3); and	Section 3.3
(7)	evidence that such costs occur solely as a consequence of the Positive Change Event.	Section 3.3

Table 3.1 – How Integral's Application addresses Section 14.2 requirements

3.2 Details and date of Positive Change Event

On 1 August 2005 the Minister for Energy and Utilities imposed additional licence conditions on Integral. These additional licence conditions entitled “Design, Reliability and Performance Licence Conditions” impose planning, reliability and performance standards and require Integral to comply with these standards over certain timeframes.

Integral considers that the imposition of the new design planning criteria, the new reliability standards, the new individual feeder standards and the new performance monitoring and reporting requirements associated with these new criteria and standards is a Positive Pass Through Event under the Determination.

Specifically, the imposition of these new criteria and standards through the licence is the coming into operation of an amendment to an Applicable Regulation *(which includes a Licence)* on/after 1 July 2004.

The new licence conditions impose additional obligations in relation to planning, reliability feeder performance and monitoring standards. The imposition of these new criteria and standards has the effect (in respect of Passthrough Distribution Services) of imposing (different) minimum standards on Integral to those immediately prior to the new licence conditions.

The imposition of these new criteria and standards results in Integral incurring materially higher costs in providing Pass Through Distribution Services.

Therefore, Integral considers that the imposition of the new licence conditions is a Regulatory Change Event, and a General Cost Pass Through Event under the Determination.

Integral believes that the date when the relevant events 'occurred' is 1 August 2005, being the date when the new licence conditions came into effect[11]. This date is on/after 1 July 2004.

3.3 Increase in costs as a result of the Positive Change Event

Table 3.2 summarises the increase in costs in the provision of Passthrough Distribution Services during the Regulatory Control Period as a result of the new licence conditions that constitute a Positive Change Event[12].

To ensure consistency with the Determination and demonstrate that the costs required are incremental to those taken into account in that Determination, the **increase in costs** in the Provision of Passthrough Distribution Services is expressed relative to the Determination allowances.

This approach quarantines the information from Integral's internal management decisions about capital delivery and work programs. In that context, Integral notes that this approach gives rise to a "negative increment" in 2004/05. This outcome reflects the reality of capital planning and differences in the profile of expenditure between the Determination and Integral's capital delivery plan to expend the same total approved allocation over the regulatory period (ie. timing differences).

[11] Integral notes that the wording in the Tribunal's Explanatory Note accompanying the licence amendments implies this.

[12] To avoid doubt, these costs exclude costs associated with the new customer service standards and which are addressed in the Specific Cost Pass Through application.

2004/05 $ million	2004/05	2005/06	2006/07	2007/08	2008/09	Total
Capital expenditure	(40.59)	3.40	89.07	93.51	200.97	346.36
Eligible Pass Through Amount - costs converted to revenue requirement (nominal $)	**(2.37)**	**(4.49)**	**1.27**	**12.58**	**31.16**	**38.15**

Table 3.2 – Summary of costs resulting from Positive Change Event

Integral's Proposed Positive Pass Through Amount is set out in section 3.4. The profile of Integral's Proposed Pass Through Amount is different to the Eligible Pass Through Amount to ensure a smooth price transition for customers, with uniform annual price increases. However, the two profiles are NPV neutral.

The breakdown of the capital expenditure, by the new licence condition requirements, is set out below.

2004/05 $ million	2004/05	2005/06	2006/07	2007/08	2008/09	Total
Design Planning Criteria	(40.59)	1.04	83.45	88.12	197.33	**329.34**
Reliability and Individual Feeder Standards	-	2.26	5.33	5.39	3.64	**16.62**
Performance Monitoring and Reporting	-	0.10	0.29	-	-	**0.39**

Table 3.3 – Breakdown of costs by licence condition

Integral notes that it expects to incur operating expenditure associated with the new licence conditions on maintenance, vegetation management, accelerated defect management, and monitoring and reporting. However, Integral is already completing similar activities and has decided not to seek pass through of the operating expenditure associated with these activities.

3.3.1 Materiality of costs

Clause 14.6 of the Determination defines Materiality as follows:

For the avoidance of doubt, a DNSP is not entitled, under this clause 14, to pass through to Distribution Customers any amount relating to a Positive Change Event if the average annual change in costs in respect of that event (as calculated in accordance with clause 2.2 of Annexure 1) does not exceed 1% of the average annual smoothed revenue requirement for the DNSP as set out in Annexure 12.

The costs incurred as a result of the new licence conditions are material under the Determination. The following table shows that the costs equate to 1.76% of the average annual smoothed revenue requirement and exceed the Materiality threshold of 1%.

Nominal $ million	2004/05	2005/06	2006/07	2007/08	2008/09
Eligible Pass Through Amount - costs converted to revenue requirement	(2.37)	(4.49)	1.27	12.58	31.16
Annexure 12 Average Revenue Requirement (smoothed)	553.20	553.20	553.20	553.20	553.20
Cost pass through as % of Annexure 12 Revenue Requirement[13]	1.76%				

Table 3.4 – Assessment of materiality of costs

3.3.2 Evidence – Capital costs resulting from new design planning criteria, reliability and individual feeder standards

The new licence conditions have significant implications for Integral's asset management plans.

Integral has analysed and interpreted the criteria and standards as a basis for estimating the resulting incremental costs. Integral notes that the licence conditions set out design planning criteria but do not tightly define how the Load at Risk (LAR) criteria should be implemented for planning purposes. Integral acknowledges that the design criteria can be interpreted in different ways, with flow on implications for the capital expenditure program. Integral has interpreted the criteria consistent with its existing network planning approach and standards, which is based on a load at risk approach.

The resulting impact on system and non-system capital costs is summarised below.

3.3.2.1 Impact on system capital expenditure

Integral's assessment of the impact on system capital expenditure of compliance with the new licence conditions is shown in Table 3.5. The analysis shows that an additional total system capital expenditure of $345.32m[14] will be required in the current regulatory period.

[13] Calculated consistent with the definition of Materiality in the Determination

[14] 2004/05$. There is an additional $1.04 million non–system capital expenditure (see sections 3.3.2.2 ($0.65m) and 3.3.3 ($0.39m)).

The vast majority of this additional expenditure ($328.70m) is associated with compliance with the **new design planning criteria** – specifically, advancement of a significant number of major projects and other distribution works in order to fulfil the LAR requirements, as interpreted by Integral. These projects are already identified in Integral's strategic asset management investment plan, but need to be advanced in time.

Integral does not believe that the **network reliability targets** will require a fundamental change in Integral's approach to total system reliability performance management in relation to capital expenditure. Hence, the additional capital expenditure required to fulfil this aspect of the new conditions is expected to be minimal and has not been included in this application.

Integral has estimated the additional capital expenditure required to comply with the **new individual feeder standards**. This totals $16.62m over the regulatory period.

2004/05 $ million	2004/05	2005/06	2006/07	2007/08	2008/09	Total
Determination baseline	243.39	269.72	248.56	250.46	211.81	**1223.94**
Capital works plan to comply with licence conditions	202.8	273.02	336.69	343.97	412.78	**1569.26**
Overall "increase" in system capital costs	(40.59)	3.30	88.13	93.51	200.97	**345.32**
Increase related to design planning	**(40.59)**	**1.04**	**82.80**	**88.12**	**197.33**	**328.70**
Increase related to individual feeder standards	**-**	**2.26**	**5.33**	**5.39**	**3.64**	**16.62**

Table 3.5 – Incremental system capital costs

PB Associates were engaged to independently review Integral's assessment of the network system capital costs. PB Associates' report is provided in Appendix B. An extract[15] from its findings is set out below.

> *"Having undertaken this review, PB Associates is able to draw the following conclusions:*
>
> - *Integral's approach to assessing the cost impact is, in general, reasonable;*
> - *the majority of the estimated additional expenditure is for compliance with the new design planning criteria;*

[15] PB Associates – "New Network Licence Conditions –Impact Assessment – An independent review", page 4.

- *the new reliability standards are likely to give rise to minimal additional expenditure;*
- *the underlying principle applied by Integral to assess the impact of the new individual feeder standards is sound;*
- *the individual project reviews confirmed application of the high-level approach adopted by Integral; and*
- *the Integral assumptions associated with [sic] the correlation of expenditure incidence with availability of new capacity are reasonable."*

Integral has prioritised the incremental system capital expenditure associated with compliance with the new licence conditions based on the following principles:

- Meet the NSW Government desired urban land release time frames in the North West and South West sectors:
    - Priority 1 – required for the next two to three years land release program
    - Priority 2 – required for the land release program in excess of three years
- Consider the magnitude of the LAR in 2008/09.

The resulting prioritised capital expenditure is in Table 3.6 below.

2004/05 $ million	2004/05	2005/06	2006/07	2007/08	2008/09	Total
Priority 1	-	-	50.84	93.51	63.57	**207.92**
Priority 2	**-**	**-**	-	-	137.40	**137.40**
Timing difference to Determination allowance	(40.59)	3.30	37.29	-	-	**-**
Total incremental system capital expenditure	**(40.59)**	**3.30**	**88.13**	**93.51**	**200.97**	**345.32**

Table 3.6 – Prioritised incremental system capital costs

The timing difference in relation to the Determination allowance reflects the differences in Integral's proposed capital expenditure profile before the new licence conditions to the expenditure profile allowed by the Tribunal in its Determination. Both capital expenditure profiles total to $1,223.9 million (2004/05 $).

3.3.2.2 Impact on non-system capital expenditure

In addition to network project costs, to comply with the design planning criteria, Integral will need to make up-front investments to enhance information systems. Non-system capital expenditure is required in 2006/07 to:

- Purchase additional planning system licences to support some of the additional network planning and analysis activities;
- Purchase an additional software module to perform network reliability based planning activities; and
- Incorporate a vegetation layer in Integral's Geographic Information System (GIS) to allow network planners to take the location of vegetation into account when planning feeder routes to maximise reliability.

2004/05 $ million	2004/05	2005/06	2006/07	2007/08	2008/09	Total
Planning system licences	-	-	0.03	-	-	**0.03**
Reliability planning package	-	-	0.21	-	-	**0.21**
Third party vegetation data	-	-	0.41	-	-	**0.41**
Total	**-**	**-**	**0.65**	**-**	**-**	**0.65**

Table 3.7 – Non-system capital expenditure associated with implementing design planning criteria

3.3.3 Evidence – Capital costs resulting from new performance monitoring and reporting requirements for general pass through conditions

Integral has estimated the costs that need to be incurred to meet the new performance monitoring and reporting requirements. Most of the incremental capital costs relate to information systems.

To comply with the new major event exclusion method, and the need to report at a feeder type level, Integral will need to make changes to its new Outage Management System (OMS). Further changes to the OMS are required to meet the new individual feeder standards, particularly to provide rolling 12-month individual feeder exception reports.

Table 3.8 following summarises the increased capital costs associated with these activities.

2004/05 $ million	2004/05	2005/06	2006/07	2007/08	2008/09	Total
Capital expenditure						
New major event exclusion method	-	0.10	-	-	-	**0.10**
Urban/rural feeder type attribution by feeder segment	-	-	0.26	-	-	**0.26**
Rolling 12 month individual feeder exception reports	-	-	0.03	-	-	**0.03**
Total	**-**	**0.10**	**0.29**	**-**	**-**	**0.39**

Table 3.8 – Incremental costs associated with Performance Monitoring and Reporting

3.4 Integral's proposed Positive Pass Through Amount

Integral has decided to propose a different profile for pass through than suggested by the profile for the Eligible Pass Through Amount. Integral's proposal has been designed to ensure a smooth price transition for customers, with uniform annual price increases.

A comparison between the eligible pass through amounts and the proposed pass through amounts is shown below. The difference in timing means that the total of the proposed Pass Through Amounts does not equal the total of the eligible amounts. However, the two profiles are neutral on an NPV basis.

$ million, nominal	2004/05	2005/06	2006/07	2007/08	2008/09	Total
	Revenue Requirement					
Eligible Pass Through Amount[16]	**(2.37)**	**(4.49)**	**1.27**	**12.58**	**31.16**	**38.15**
Proposed Positive Pass Through Amount	**-**	**-**	**5.00**	**10.00**	**20.15**	**35.15**

Table 3.9 - Proposed Pass Through Amounts

Integral seeks approval by the Tribunal under section 14.2(b) of the Determination to pass through its proposed Positive Pass Through Amount set out in Table 3.9 above.

[16] The eligible pass through amount has been calculated by **translating the increased capital and operating system and non-system costs to revenue requirement terms**

4 Specific Pass Through

4.1 Summary

Under Clause 15 of the Determination, Integral must give the Tribunal a written statement and accompanying evidence to support the Tribunal's Determination.

This Chapter addresses the requirements of that statement as set out in Clause 15.2 (a) as follows:

Section 15.2 Requirements		Integral's Application Reference
(1)	the details of the Specific Pass Through Event concerned;	Section 4.2
(2)	the date the Specific Pass Through Event occurred;	Section 4.2
(3)	the increase in costs in the provision of Passthrough 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 Specific Pass Through Event (i.e. the Eligible Pass Through Amount (as calculated by the DNSP) in respect of that Specific Pass Through Event);	Section 4.3
(4)	the Specific Pass Through Amount the DNSP proposes in relation to the Specific Pass Through Event;	Section 4.4
(5)	the amount of that Specific Pass Through Amount that the DNSP proposes should be passed through to Distribution Customers in each Year during the Regulatory Control Period;	Section 4.4
(6)	of the actual and likely increase in costs referred to in clause 15.2(a)(3); and	Section 4.3
(7)	evidence that such costs occur solely as a consequence of the Specific Pass Through Event.	Section 4.3

Table 4.1 – Determination Specific Pass Through requirements

4.2 Details and date of Specific Pass Through Event

The Determination provides for Integral to apply to the Tribunal to pass through amounts associated with Specific Pass Through Events. The potential for new licence conditions regarding customer service standards and payments was raised by the DNSPs and acknowledged by the Tribunal during the Determination process. The Tribunal's decision was that the impacts of such a change would be addressed through the new specific pass through mechanism.

As set out in section 2.1, Specific Pass Through Events include “the imposition of guaranteed customer service standards” 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”[17].

The new licence conditions for the imposition of Customer Service Standards effected on 1 August 2005 by the Minister for Energy and Utilities are a Specific Pass Through Event[18] under the Determination.

4.3 Increase in costs as a result of the Specific Pass Through Event

The following table summarises the increase in costs in the provision of Passthrough Distribution Services that Integral is likely to incur until the end of the Regulatory Control Period as a result of the new licence conditions which constitute a Specific Pass Through Event.

2004/05 $ million	2004/05	2005/06	2006/07	2007/08	2008/09	Total
Incremental capital expenditure	-	-	0.46	-	-	**0.46**
Incremental operating expenditure	-	0.34	1.76	1.74	1.74	**5.58**
Eligible Pass Through Amount - costs converted to revenue requirement (nominal $)	**-**	**0.35**	**1.88**	**1.93**	**1.97**	**6.13**

Table 4.2 – Estimated increase in costs for Specific Pass Through Events

Integral’s Proposed Specific Pass Through Amount is set out in section 4.4. The profile of Integral’s Proposed Specific Pass Through Amount is different to the Eligible Pass Through Amount to ensure a smooth price transition for customers, with uniform annual price increases. However, the two profiles are NPV neutral.

The breakdown of the costs, by the new licence condition requirements, is set out in Table 4.3 following.

[17] As defined in Annexure 1 of the NSW Electricity Distribution Pricing 2004/05 to 2008/09 Determination No 2, 2004.

[18] ibid.

2004/05 $ million	2005/06	2006/07	2007/08	2008/09	Total
Customer Service Standard payments					
Incremental operating expenditure	-	0.95	0.95	0.95	**2.84**
Establishment of Customer Service Standard systems and processes					
Incremental capital expenditure	-	0.20	-	-	**0.20**
Incremental operating expenditure	-	0.04	0.04	0.04	**0.12**
Administration of Customer Service Standard payments					
Incremental operating expenditure	0.10	0.56	0.54	0.54	**1.75**
Performance monitoring and reporting					
Incremental capital expenditure	-	0.26	-	-	**0.26**
Incremental operating expenditure	0.24	0.21	0.21	0.21	**0.87**

Table 4.3 – Detailed breakdown of estimated increase in costs for Specific Pass Through Event

4.3.1 Evidence – Customer Service Standard payments

4.3.1.1 Approach to estimating cost of payments to customers

The new licence conditions require Customer Service Standard payments to customers where Integral does not comply with the interruption duration and interruption frequency standards.

The approaches Integral has used to estimate the likely Customer Service Standard payments associated from non-compliance with the frequency and duration standards of the new licence conditions are set out below.

Payment associated with not complying with the frequency standard

Integral's approach was to:

1. Identify all substations with nine or more interruptions during 2004/05 (the only year for which this information is available);

2. Categorise the default substations as metro or non-metro depending upon their Local Government Area. Whether the customers were urban or rural was determined using population data based on the 2001 Census results, the ABS publication 2016.1 “Selected Characteristics for Urban Centres and Localities” and reference to GIS maps;

3. Determine which substation interruptions exceeded the new licence requirement thresholds; and

4. Determine the number of customers for the relevant substations and the resulting number of potential claims.

Based on this approach, it was estimated that 505 frequency claims could have been made in 2004/05.

Duration standard

Integral’s approach was to:

1. Identify all incidents in the last three financial years that had a duration of 10 hours or more;

2. Determine if the incidents identified occurred in a metro or non-metro, urban/rural location; and

3. Calculate the potential number of claims based on the number of customers that exceeded the threshold using the percentage of customers restored at each staged restoration step.

Based on this approach, it was estimated that 12,654 duration claims could have been made in 2004/05. A similar analysis was undertaken for 2002/03 and 2003/04. The data in 2003/04 was significantly impacted by the natural declared disaster of 24 and 25 August 2003 and demonstrated significant volatility, with a potential for up to 95,000 claims. As a result, Integral’s application is based on the results of the 2004/05 financial year, which is at the lower end of the range.

4.3.1.2 Estimated cost of payments to customers

The estimated cost of payments was calculated using the potential number of claims estimated using the approaches set out in 4.3.1.1 above. It was assumed that 90% of claims are payable.

In addition, consistent with the licence conditions, the maximum payments were capped at $320/customer (ie. four events as specified in the new licence conditions). This resulted in the following estimate of the annual cost of Customer Service Standard payments (Table 4.4).

2004/05 $	Potential claims	Potential CSS payment
Frequency	505	$40,400
Duration	12,654	$1,012,320
Total potential CSS payment		$1,052,720
Total estimated Customer Service Standard payment assuming that 90% of claims are payable		**$947,448**

Table 4.4 - Estimated incremental Customer Service Standard payments

4.3.2 Evidence – costs to establish Customer Service Standard systems and processes

Integral has estimated the following incremental operating and capital expenditure costs to establish systems and processes to meet the new Customer Service Standard licence conditions.

2004/05 $ million	2005/06	2006/07	2007/08	2008/09	Total
Outage Management System					
Incremental capital expenditure	-	0.10	-	-	**0.10**
Incremental operating expenditure	-	0.02	0.02	0.02	**0.06**
Ellipse cheque run process					
Incremental capital expenditure	-	0.10	-	-	**0.10**
Incremental operating expenditure	-	0.02	0.02	0.02	**0.06**

Table 4.5 - incremental operating and capital expenditure costs associated with establishing systems and processes

The basis for the cost estimates set out in Table 4.5 above, are as follows:

- Outage Management System (OMS) report and extract - a new reporting process is required to capture the validation of customer claims and provide an output for the Customer Service Standard payment process.
- Ellipse cheque run process - modify the existing Ellipse cheque run process to cater for the processing of the Customer Service Standard payments from the new OMS.

4.3.3 Evidence – Costs to administer Customer Service Standard on ongoing basis

Integral will need to undertake new and additional activities to administer Customer Service Standard licence conditions, particularly in relation to the process for payment of claims. Additional activities include:

1. Taking the initial complaint call;
2. Investigating the claim;
3. Processing the claim;
4. Notifying the customer of Integral's assessment; and
5. Making payment.

In addition, Integral must meet the advertising requirements of the new licence conditions.

The resulting estimated incremental operating costs associated with these administration and advertising activities are set out in Table 4.6.

2004/05 $	2005/06	2006/07	2007/08	2008/09	Total
Initial call registration	-	25,779	25,779	25,779	**77,336**
Claims section	-	69,740	69,740	69,740	**209,220**
Engineering Performance - Duration	-	189,243	189,243	189,243	**567,729**
Engineering Performance - Frequency	-	15,139	15,139	15,139	**45,418**
Engineering Performance - Data entry	-	49,203	49,203	49,203	**147,609**
Customer notification - accepted	-	8,967	8,967	8,967	**26,900**
Customer notification - denied	-	19,926	19,926	19,926	**59,777**
Credit applied in customer bill	-	15,243	15,243	15,243	**45,730**
Cheque raised	-	31,982	31,982	31,982	**95,945**
Negotiate Complaint Outcome	-	19,747	19,747	19,747	**59,240**
Contingency margin of 10%	-	44,497	44,497	44,497	**133,490**
Advertising costs	104,086	74,903	50,584	50,584	**280,156**
Total incremental operating expenditure	**104,086**	**564,367**	**540,048**	**540,048**	**1,748,550**

Table 4.6 - Estimated incremental operating costs associated with the administration and advertising of the Customer Service Standard payments

Integral determined the costs associated with each activity based on the estimated time to undertake the activity and the associated labour costs. Table 4.7 sets out Integral's cost input assumptions.

Task, 2004/05 $	**Task duration (mins)**	**Unit cost per hour**	**Duration claims**	**Frequency claims**	**Total claims**
Initial call registration	3	39.66	24,787	991	**25,779**
Claims section	7	45.98	67,058	2,682	**69,740**
Engineering Performance - Duration	20	45.42	189,243	-	**189,243**
Engineering Performance - Frequency	40	45.42	-	15,139	**15,139**
Engineering Performance - Data entry	5	45.43	47,311	1,892	**49,203**
Customer notification - accepted	1	45.99	8,622	345	**8,967**
Customer notification - denied	20	45.99	19,159	766	**19,926**
Credit applied in customer bill	2	45.98	14,657	586	**15,243**
Cheque raised	25	41.40	30,751	1,230	**31,982**
Negotiate Complaint Outcome	15	60.76	18,987	759	**19,747**
Contingency margin of 10%			42,058	2,439	**44,497**

Table 4.7 – Estimated cost input assumptions associated with administration and advertising of the Customer Service Standard payments

The assumptions underpinning Integral's estimates are:

Parameter	**Assumption**
Labour costs include appropriate level salary and associated on costs	
Number of duration claims – see s4.3.1.1 above	12,500
Number of frequency claims – see s4.3.1.2 above	500
Percentage of claimants who call – given the advertising requirements of the new licence conditions it is assumed that one claim will be received for each eligible party, with 10% of claims being ineligible	100%
Percentage of claims denied	10%

Table 4.8 - Assumptions underlying incremental operating costs associated with the administration and advertising of the Customer Service Standard payments

Integral's estimate of the additional costs associated with advertising allows for the following activities:

1. Once-off development of a communications plan, including media materials, in 2005/06;

2. Preparation of a customer information brochure in 2005/06 to be inserted annually into customer bills;

3. Annual advertising in-franchise local press and one metro press; and

4. Once off preparation in 2005/06 of frequently asked questions for Integral's website.

4.3.4 Evidence – costs to monitor and report on Customer Service Standard

Integral has estimated the following incremental operating and capital expenditure costs associated with monitoring and reporting on the Customer Service Standard:

2004/05 $ million	2005/06	2006/07	2007/08	2008/09	Total
New premise area classifications					
Incremental capital expenditure	-	0.26	-	-	**0.26**
Incremental operating expenditure	-	0.08	0.08	0.08	**0.24**
CSS to GIS address matching					
Incremental operating expenditure	0.08	0.08	0.08	0.08	**0.32**
Additional GIS data capture					
Incremental operating expenditure	0.15	0.05	0.05	0.05	**0.30**

Table 4.9 - Estimated incremental operating and capital expenditure costs associated with monitoring and reporting on the Customer Service Standard

The cost estimates set out in Table 4.9 take account of the costs of:

- New premise area classifications (eg. Metro, non-metro, urban, non-urban) attribution - as a result of the reporting requirement to classify customers by metro/non-metro etc, a change is required to the design of Integral's new OMS.

- Customer Service Standard to GIS address matching - additional (and ongoing) data scrubbing is required to practically maintain the high level of synchronisation between the address data in the customer system and the address data in Integral's GIS provided by NSW Department of Lands. This address matching is the method that ties individual customers to Integral's low voltage network.

- Additional GIS data capture - additional GIS data capture is required to meet the Customer Service Standard reporting requirements down to the individual customer level.

Integral notes that these costs are incremental and have not been provided for in the Determination, either directly through the revenue building blocks nor the price path mechanism.

4.3.4.1 Category of Pass Through Event

To the extent that the Tribunal finds that the capital and operating costs for monitoring and reporting on customer service standards do not relate to the Specific Pass Through Event, Integral requests the Tribunal consider these costs as part of its General Pass Through Event application.

4.4 Integral's proposed Specific Pass Through Amount

Integral has decided to propose a different profile for pass through than suggested by the profile for the Eligible Pass Through Amounts. The profile of Integral's proposed Specific Pass Through Amounts has been designed to ensure a smooth price transition for customers.

A comparison between the Eligible Pass Through Amounts and the proposed Specific Pass Through Amounts is shown below. The difference in timing means that the total of the proposed Specific Pass Through Amounts does not equal the total of the eligible amounts. However, the two profiles are neutral on an NPV basis.

The following table sets outs Integral's proposed specific annual and total pass through amounts.

$ million, nominal	2004/05	2005/06	2006/07	2007/08	2008/09	Total
	Revenue Requirement					
Eligible Pass Through Amount[19]	**-**	**0.35**	**1.88**	**1.93**	**1.97**	**6.13**
Proposed Specific Pass Through Amount	**-**	**-**	**1.50**	**2.50**	**2.27**	**6.27**

Table 4.10 – Integral's Proposed Specific Pass Through Amount

Integral seeks approval by the Tribunal under section 15.2(b) of the Determination to pass through its proposed Specific Pass Through Amount set out in Table 4.10 above.

[19] The Eligible Pass Through Amount has been calculated by **translating the increased capital and operating system and non-system costs to revenue requirement terms**

5 Customer outcomes

While the new licence conditions are focussed on improving the reliability and performance of Integral's network, the costs of complying with these conditions is significant. The increase in operating and capital costs means that additional revenue needs to be recovered by Integral in each of the remaining years in the regulatory period. In turn, distribution tariffs will need to rise, with flow on implications for retail tariffs.

This submission includes Integral's separate Applications for a General Cost Pass Through and a Specific Cost Pass Through. The proposed pass through amounts are set out in Table 5.1 following.

2004/05$ million	2004/05	2005/06	2006/07	2007/08	2008/09	Total
General Cost Pass Through Event						
Incremental capital expenditure	(40.59)	3.40	89.07	93.51	200.97	346.36
Proposed Positive Pass Through Amount (Revenue requirement nominal $ million)	**-**	**-**	**5.00**	**10.00**	**20.15**	**35.15**
Specific Cost Pass Through Event						
Incremental capital expenditure	-	-	0.46	-	-	0.46
Incremental operating expenditure	-	0.34	1.76	1.74	1.74	5.58
Proposed Specific Pass Through Amount (Revenue requirement nominal $ million)	**-**	**-**	**1.50**	**2.50**	**2.27**	**6.27**

Table 5.1 – General Cost Pass Through and Specific Cost Pass Through of costs to network tariffs - proposed Positive Pass Through Amounts and Specific Pass Through Amounts resulting from new customer service standards

Integral has analysed the combined impact of the overall impact of the General Cost Pass Through Event and the Specific Cost Pass Through Event on its customers. This analysis shows that the pass through will increase the X factor from -1.5% to -2.7% per annum over the period 1 July 2006 to 30 June 2009.

The increase in the X factor translates to an increase of approximately $5 each year above the existing Determination for the typical domestic customer (with an annual consumption of 7.5 MWh), or a cumulative increase of $30 over the three years remaining in the regulatory period. The annual increase is about 0.5 percent of the total electricity costs for a domestic customer.

For an average general supply customer (with an annual consumption of 20 MWh), the annual increase is estimated to be around $11 above the existing Determination, or a cumulative increase of $66 over the three years remaining in the regulatory period. This annual increase is less than 0.5 percent of the total electricity costs for that customer.

Table 5.2 below summarises Integral's analysis of the impact of the proposed pass through amounts on residential and business customers' bills.

Customer type and annual consumption, nominal $	Estimated Distribution bill (2006/07) – Before licence conditions	Estimated Distribution bill (2006/07) – After licence conditions	Additional annual cost	Estimated percentage of total retail bill
Residential				
Low usage (3.5MWh)	**$249**	**$252**	**$3**	**0.5%**
Typical usage (7.5MWh)	**$453**	**$458**	**$5**	**0.5%**
High usage (10MWh)	**$592**	**$599**	**$7**	**0.5%**
Business				
20MWh (Typical usage)	**$911**	**$922**	**$11**	**0.4%**
40MWh	**$1,829**	**$1,850**	**$21**	**0.4%**
80MWh	**$3,674**	**$3,716**	**$42**	**0.4%**

Table 5.2 – Analysis of customer impacts

Appendix A - Glossary

Term	Definition
CPI	Consumer Price Index
CSS	Customer Service Standard
Determination	The Tribunal's 2004 Network Determination
DNSP	Distribution Network Service Provider
Eligible Pass Through Amount	Per the Determination
Final Report	The Tribunal's NSW Electricity Distribution Pricing, 2004/05 to 2008/09, Final Report
General Pass Through Event	Per the Determination
Integral	Integral Energy
LAR	Load at risk
Materiality	Per the Determination
MEU	Ministry of Energy and Utilities
MWh	Megawatt Hour
NPV	Net present value
OMS	Outage Management System
Pass Through Amount	Per the Determination
Passthrough Distribution Services	Per the Determination
Positive Change Event	Per the Determination
Regulatory Control Period	Per the Determination
Specific Pass Through Amount	Per the Determination
Specific Pass Through Event	Per the Determination
Tribunal	Independent Pricing and Regulatory Tribunal of NSW

Appendix B – PB Associates Report

PB ASSOCIATES

NEW NETWORK LICENCE CONDITIONS – IMPACT ASSESSMENT

An independent review

Prepared for

The power is in your hands

***PB Associates** Quality System:*

Document Reference	:	p:\158345\NewLicenceCondImpactAssessment_v7_0.doc
Report Revision	:	7_0
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SECTIONS

In preparing this report, PB Associates has relied upon documents, data, reports and other information provided by Integral Energy as referred to in the report. Except as otherwise stated in the report, PB Associates has not verified the accuracy or completeness of the information. To the extent that the statements, opinions, facts, information, conclusions and/or recommendations in this report are based in whole or part on the information, those conclusions are contingent upon the accuracy and completeness of the information provided. PB will not be liable in relation to incorrect conclusions should any information be incorrect or have been concealed, withheld, misrepresented or otherwise not fully disclosed to PB. The assessment and conclusions are indicative of the situation at the time of preparing the report. Within the limitations imposed by the scope of services and the assessment of the data, the preparation of this report has been undertaken and performed in a professional manner, in accordance with generally accepted practices and using a degree of skill and care ordinarily exercised by reputable consultants under similar circumstances. No other warranty, expressed or implied, is made.

EXECUTIVE SUMMARY

Integral Energy has engaged PB Associates to undertake a high-level review of the network business impacts of compliance with the new ‘Design, Reliability and Performance’ licence conditions.

The aim of this work is to review the methodology and process adopted by Integral Energy in its assessment of the impact on the Integral Energy network business of compliance with the new mandated standards. This report sets out the PB Associates view on the validity of the capital costs which Integral Energy is seeking to include in its pass-through application.

The main steps undertaken by PB Associates in this review have been to:

- review the existing Integral Energy standards, procedures and reports and undertake a high-level review of the existing forward capex programme;
- audit a selection of planned capital projects;
- understand and review the Integral Energy approach to the assessment of the imposition of the new licence conditions; and
- provide advice on the validity of the methodology and process adopted by Integral Energy in its assessment of the pass through costs.

This review by PB Associates is a high-level assessment only of Integral Energy’s network capital expenditure planning processes and the validity of additional capital expenditure projections as outlined above. It does not constitute a detailed review of the efficiency and/or efficacy of Integral’s complete forward-looking capital programme.

Having undertaken this review, PB Associates is able to draw the following conclusions:

- Integral Energy’s approach to assessing the cost impact is, in general, reasonable;
- the majority of the estimated additional expenditure is for compliance with the new design planning criteria;
- the new reliability standards are likely to give rise to minimal additional expenditure;
- the underlying principle applied by Integral Energy to assess the impact of the new individual feeder standards is sound;
- the individual project reviews confirmed application of the high-level approach adopted by Integral Energy; and
- the Integral Energy assumptions associated the correlation of expenditure incidence with availability of new capacity are reasonable.

Table A shows Integral Energy’s estimation of the impact of compliance with the new licence conditions. The analysis undertaken by Integral Energy suggest that an additional total of $345m will be required in the current regulatory period.

Table A – Estimated variation in total capex for compliance for new licence conditions[1]

	2004/05 ($m)	2005/06 ($m)	2006/07 $m)	2007/08 ($m)	2008/09 ($m)	Total ($m)
IPART determination	243.39	269.72	248.56	250.46	211.81	1,223.94
Total revised plan (DEUS)	202.80	273.02	336.69	343.97	412.78	1,569.26
Variation	-40.59	3.3	88.13	93.51	200.97	345.32

1 2004/05 dollars (real).

1. INTRODUCTION AND BACKGROUND

Integral Energy has engaged PB Associates to undertake an independent review of Integral Energy's assessment of the increased capital costs required to comply with the new 'Design, Reliability and Performance' licence conditions.

1.1 THE NEW LICENCE CONDITIONS

Additional licence conditions were imposed on Integral Energy on 1st August 2005 by the Minister for Energy and Utilities. These new requirements, entitled "Design, Reliability and Performance Licence Conditions", require Integral Energy to comply with prescribed standards relating to network reliability performance. The new conditions require that these standards are met over certain timeframes.

Cost and pricing implications

The Independent Pricing and Regulatory Tribunal of NSW (IPART) released Determination No 2, 2004 in June 2004. Part of the Determination requires the Tribunal to determine a pass through amount for a positive pass through event. PB Associates understands that the imposition of the new licence conditions is a *general cost pass through* event under the IPART Determination. Consequently, Integral Energy is applying to IPART to pass through additional costs which it is expected to occur as a direct result of the imposition of the new licence conditions.

The existing Integral Energy capital allowance for the present regulatory period is given in Table 1-1.

Table 1-1 – Total existing capital expenditure allowance (IPART)

	2004/05 ($m)[2]	*2005/06 ($m)*	*2006/07 $m)*	*2007/08 ($m)*	*2008/09 ($m)*	*Total ($m)*
IPART determination[3]	243.39	269.72	248.56	250.46	211.81	1,223.94

1.2 OBJECTIVE AND SCOPE OF THE WORK

The objective of this project is to review the methodology and process adopted by Integral Energy in its assessment of the impact on the Integral Energy network business of compliance with the new mandated design, reliability and performance standards.

This report sets out the PB Associates view on the validity of the capital costs which Integral Energy is seeking to include in its pass-through application.

1.3 THE APROACH ADOPTED BY PB ASSOCIATES FOR THIS REVIEW

The review considers Integral Energy's assessment of the *additional* capital costs which will be incurred in the current regulatory period as a result of meeting the new licence conditions. PB Associates review is premised on the following assumptions:

[2] 2004/05 dollars (real).

[3] From Integral Energy spreadsheet '010 IPART 2004 Determination allowances tc.xls' – as provided to PB Associates by Integral Energy on 8 November 2005.

- the estimates of additional capital cost derived by Integral Energy do not consider possible resource constraints which could affect the ability to deliver the required changes;

- the potential impact on operational expenditure levels are not considered; and

- the focus is on projected capital expenditure increases for the current regulatory period only.

The main steps undertaken by PB Associates are as follows:

- review of the existing Integral Energy standards, procedures and reports;

- undertake a high-level review of the existing forward capex programme;

- audit of a selection of planned capital projects;

- review the Integral Energy approach to the assessment of the imposition of the new licence conditions;

- overlay the new licence conditions and assess the implication on sample projects; and

- provide advice on the validity of the methodology and process adopted by Integral Energy in its assessment of the pass through costs.

It is to be noted that this review by PB Associates is a high-level assessment only of Integral Energy's network capital expenditure planning processes and the validity of additional capital expenditure projections as outlined above. It does not constitute a detailed review of the efficiency and/or efficacy of Integral's complete forward-looking capital programme.

1.4 THE STRUCTURE OF THIS REPORT

In Section 2 of this report we describe the new licence conditions and compare the requirements with the existing planning standards used by Integral Energy. In Section 3 we review the approach and methodology adopted by Integral Energy in assessing the cost impact of full compliance with the new requirements; this addresses each element of the requirements (design planning, reliability and individual feeder performance). A review of sample projects is also included in Section 3. Our conclusions are set out in Section 4.

2. THE NEW LICENCE CONDITIONS

Additional licence conditions, entitled "Design, Reliability and Performance Licence Conditions", were imposed on Integral Energy on 1st August 2005 by the Minister for Energy and Utilities. These licence conditions require Integral Energy to comply with additional conditions relating to network reliability performance.

2.1 DESCRIPTION OF THE NEW REQUIREMENTS

The Design, Reliability and Performance licence conditions provide for new minimum standards in the following areas:

- design planning criteria (network security);
- reliability standards;
- individual feeder standards; and
- customer service standards[4].

The specific requirements relevant to the Integral Energy distribution network in each of these areas is described in more detail below.

2.1.1 Design planning criteria (network security)

The Design Planning criteria sets out the standards to be used by a distribution network service provider in planning, developing and managing its distribution system to ensure minimum levels of redundancy (and hence, security of supply) and that the distribution network is capable of delivering the required level of (output) reliability.

The new standards prescribe network redundancy levels, and associated maximum customer interruption times, for a range of network element and load types. The network elements include the following:

- sub-transmission line;
- sub-transmission substation;
- zone substation;
- distribution feeder; and
- distribution substation.

For Integral Energy, the relevant 'load types' include:

- urban and non-urban[5] sub-transmission and zone substations having a total load not less than 10MVA[6];

4 The customer service standards aim to recognise those customers experiencing poor reliability of supply by imposing a requirement for Integral Energy to pay customers a Guaranteed Customer Service Standard (GCSS) payment for failure to meet specific reliability performance standards. This aspect of the new licence conditions, and the potential impact on Integral Energy, is beyond the scope of this review by PB Associates.

- non-urban sub-transmission and zone substations having a total load less than 10MVA;
- urban and non-urban sub-transmission lines;
- urban distribution feeders (supplying towns having no fewer than 15,000 connected customers);
- urban distribution feeders (supplying towns having fewer than 15,000 connected customers);
- non-urban distribution feeders; and
- urban and non-urban distribution substations.

Table 2-1 – Summary of new design planning criteria (interim arrangements)

Network element	***Load type***	***Load magnitude***	***Security standard***	***Customer interruption time***
Sub-transmission line	urban & non urban	⩾10MW	n-1	<1 minute
	non-urban	<10MW	n	repair time[7]
Sub-transmission sub-station	urban and non-urban	any	n-1	<1 minute
Zone-substation	urban and non-urban	⩾10MW	n-1	<1 minute
	non-urban	<10MW	n	repair time
Distribution feeder	urban (⩾15,000)	any	n-1	<4 hours
	urban (<15,000)	any	n	repair time
	non-urban	any	n	repair time
Distribution substation	urban and non-urban	any	n	repair time

The new licence provisions require that Integral Energy comply with the prescribed design planning criteria licence conditions in relation to *network elements* installed from 1 July 2007 from the date of installation. Furthermore, Integral Energy is required to comply with the design planning criteria in respect to *all of its network elements* from 1 July 2009.

The standards applicable to Integral Energy for each of the network elements set out in Table 2-1, are described below.

5 The definitions for 'urban' and 'non-urban' distribution feeders are given in the new licence condition document – 'Design, Reliability and Performance Licence Conditions Impose on Distribution Network Service Providers by the Minster for Energy and Utilities, 1 August 2005, Section 19.

6 For Integral Energy the 10MVA load threshold is replaced by 5MVA as from 30 June 2014.

7 Repair time is 'best practice' repair time.

Sub-transmission line

Integral Energy's sub-transmission line assets operate at 132kV[8], 66kV and 33kV. The sub-transmission system is generally constructed and operated as a meshed network.

The new network licence conditions require that by 1 July 2009 all of the Integral Energy sub-transmission circuits having a load greater than (or equal to) 10MVA must be constructed with sufficient redundancy such that an unplanned outage[9] of a system element does not result in anything more than a momentary interruption to connected customers[10]. This ability to withstand the unexpected loss of a single critical (but credible) network element is defined as being an "n-1" security standard.

Sub-transmission lines in *non-urban* areas having a load magnitude less than 10MVA do not require redundancy to provide for a contingency and, in the event of such an occurrence, Integral Energy may restore supplies to affected customers in the time taken to undertake the necessary repairs[11].

Load at risk

The new licence conditions therefore require there to be no LAR associated with sub-transmission lines[12] as of 30 June 2009.

Sub-transmission substation

Integral Energy's sub-transmission substations (STS) transfer electricity from the 132kV network to the 66kV or 33kV networks[13]. Integral Energy currently has 21 sub-transmission substations.

The new licence conditions require that all STS shall have sufficient redundancy to ensure that an unplanned outage does not result in anything more than a momentary interruption to connected customers – i.e. an n-1 security standard.

Load at risk

A relaxation of the standard exists for STS until 30 June 2012 whereby a limited amount of load-at-risk (LAR) is permitted for a limited period of time in any given period. Specifically, that in any one year[14], LAR is permitted where the probability is less than 1% that load may not be able to be sustained following a failure. The result is that the licence condition accepts that for a limit period of time, an unplanned network contingency may result in interruptions in customer supplies for periods exceeding the 1 minute (momentary) standard.

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8 Integral Energy generally refer to the 132kV network as a 'transmission' network although the licence conditions categorise all assets operating at 33kV and above (including 132kV) as 'sub-transmission'.

9 The licence conditions define the outage standard as being based on consideration of a credible contingency, generally limited to major items of plant with either significant failure rates and/or requiring routine outages for maintenance (e.g. zone transformers).

10 The licence conditions specify that the customer interruption time shall be less than 1 minute in duration.

11 Defined as being 'best practice' repair time.

12 Having a rating greater than or equal to 5MVA.

13 A substation having a primary voltage of 132kV and secondary voltage of 66kV or 33kV is generally referred to as a 'transmission substation' within Integral Energy.

14 Defined as a financial year.

The relaxation of the standard lapses in 2012 by which time all LAR associated with STS must be eliminated.

The standard applies to all STS, regardless of capacity or load magnitude.

Zone substation

Integral Energy's zone substations transfer power from the sub-transmission networks to elements of the distribution system operating at, or below, 22kV. Integral Energy currently has 144 zone substations[15].

The new licence conditions require that all zone substations having a load magnitude greater than (or equal to) 10MVA[16] must have sufficient redundancy to ensure that an unplanned outage does not result in anything more than a momentary interruption[17] to connected customers – i.e. an n-1 security standard.

Zone substations in *non-urban* areas having a load magnitude less than 10MVA[18] do not require redundancy to provide for a contingency and, in the event of such an occurrence, Integral Energy may restore supplies to affected customers in the time taken to undertake the necessary repairs[19].

Load at risk

A relaxation of the standard exists for zone substations having a load magnitude greater (or equal to) 10MVA[20] whereby LAR is permitted where the probability is less than 1% that load may not be able to be sustained following a failure. The result is that the licence condition accepts that for limit period of time, an unplanned network contingency may result in interruptions in customer supplies for periods exceeding the 1 minute (momentary) standard. For zone substations having a capacity greater than (or equal to) 20MVA, this relaxation ceases at 2019[21].

Distribution feeder

Integral Energy's distribution feeders are generally defined as those operating at a voltage in excess of 1000V (but not exceeding 22kV) which provide a connection between the zone substations and distribution substations[22]. This comprises several thousand kilometres of high voltage overhead line and underground cable.

The new licence conditions differentiate between high voltage distribution feeders supplying large urban towns[23] and all others. In the case of the former, the new licence conditions require that all feeders must have sufficient redundancy to ensure that an unplanned outage of a single (critical) network element does not result in prolonged

15 Electricity Network Performance Report 2003/2004, Integral Energy, October 2004.

16 For Integral Energy the 10MVA load threshold is replaced by 5MVA as from 30 June 2014.

17 Defined as being less than 1 minute in duration.

18 For Integral Energy the 10MVA load threshold is replaced by 5MVA as from 30 June 2014.

19 Defined as being 'best practice' repair time.

20 For Integral Energy the 10MVA load threshold is replaced by 5MVA as from 30 June 2014.

21 The licence conditions state that the 1% LAR associated with zone substations having a capacity not less than 20MVA must be eliminated with the next two regulatory periods following the present regulatory period.

22 The licence condition definitions exclude short sections off the trunk feeder used to supply a small number of distribution substations (e.g. a spur line into a peninsular or valley.

23 A large urban town is defined as being one having no fewer than 15,000 connected customers.

interruptions to customer supplies. In the event of an unplanned outage of such a distribution feeder, it is required supplies to customers should be restored within 4 hours[24].

The new conditions require that Integral Energy's existing urban distribution feeders comply with the security requirement by 2014[25]. The new conditions therefore require that there shall be no LAR on distribution feeders supplying large urban town in the Integral Energy area after 2014.

Non-urban distribution feeders do not require redundancy to provide for a contingency and, in the event of such an occurrence, Integral Energy may restore supplies to affected customers in the time taken to undertake the necessary repairs[26].

Distribution substation

Integral Energy's distribution substations have primary voltages of 11kV and 22kV. Distribution substations do not require redundancy to provide for a contingency and, in the event of such an occurrence, Integral Energy may restore supplies to affected customers in the time taken to undertake the necessary repairs.

2.1.2 Reliability standards (SAIDI, SAIFI)

The new licence conditions place an imposition on Integral Energy to comply with minimum average network reliability standards for Integral Energy, across its distribution network. The reliability standards provided for in the new licence conditions take the form of minimum SAIDI[27] and SAIFI[28] levels for each Integral Energy feeder type[29].

The SAIDI and SAIFI compliance levels provide for a number of exclusions. These include:

- planned interruptions;
- momentary interruptions (<1 minute duration);
- interruptions due to generation shortfalls, a failure of the transmission system, automatic (under-frequency) load shedding[30] or a relevant statutory direction to interrupt electricity supplies[31]; or

24 A 4-hour restoration time infers the use of manual switching to sectionalise the faulty network and to restore supplies.

25 The licence condition states that Integral Energy must comply by 'the end of the next *regulatory period* following the present *regulatory period*.

26 Defined as being 'best practice' repair time.

27 System Average Interruption Duration index. The total minutes, on average, that a customer is without electricity in a year. Calculated as the sum of the duration of each sustained customer interruption (minutes) divided by the total number of customers (financial year average) of the licence holder. i.e. the total number of customer-minutes lost per connected customer over a year.

28 System Average Interruption Frequency Index. The average number of occasions per year that each customer is interrupted. Calculated as the total number of sustained interruptions divided by the total number of customers (financial year average) of the licence holder.

29 Under the reliability standard, feeders are classified as either urban, short-rural or long-rural.

30 As described in the *Power System Security and Reliability Standards* made under the National Electricity Rules.

31 As detailed in Schedule 4 (Excluded Interruptions) of the new Licence Conditions paper.

- an interruption which commences on a *major event day*[32] or one which is caused by a customer's electrical installation or failure of that electrical installation.

The minimum SAIDI and SAIFI reliability standards imposed on Integral Energy by the new licence conditions are given in Table 2-2.

Table 2-2 – Integral Energy reliability standard targets[33]

Feeder type	*2005/06*	*2006/07*	*2007/08*	*2008/09*	*2009/10*	*2010/11*
SAIDI (minutes per customer)						
Urban[34]	90	88	86	84	82	80
Short rural[35]	300	292	284	276	268	260
Long rural[36]	n/a	n/a	n/a	n/a	n/a	n/a
SAIFI (number per customer)						
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

2.1.3 Individual feeder performance

The new licence conditions also include minimum standards for individual feeder performance. The stated aim of this element of the new licence conditions is to ensure that distribution businesses continually focus on poorly performing feeders. The new requirements are provided in Table 2-3.

32 PB Associates understands that the definition of *major event day* is as per the IEEE Standard 1366-2003 for Electric Power Distribution Reliability Indices which uses a statistical method known as the "Beta Method" to determine a threshold value T_{MED}.

33 'Design, Reliability and Performance Licence Conditions Impose on Distribution Network Service Providers by the Minster for Energy and Utilities', 1 August 2005, Schedule 2.

34 The new licence conditions define an 'urban' feeder as one having an actual maximum demand over the reporting period (per total feeder route length) greater than 0.3MVA/km which is not a *CBD feeder*, *short-rural* feeder or *long-rural* feeder. Integral Energy does not have *CBD feeders*.

35 The new licence conditions define a 'short-rural' feeder as one having a total feeder route length less than 200km and which is not a *CBD feeder* or an *urban* feeder. Integral Energy does not have *CBD feeders*.

36 The new licence conditions define a 'long-rural' feeder as one having a total feeder route length greater than 200km and which is not an *urban* feeder. Integral Energy has no long rural feeders.

Table 2-3 – New imposed individual feeder standards

Feeder type	*SAIDI*	*SAIFI*
Urban	350	4
Rural-short	800	6.5
Rural-long	1200	10

These standards are based on the same exclusion rules (and methodology) as used for the general reliability standards. There is also a requirement for Integral Energy to report where individual feeders do not comply with the individual feeder standard and to prepare action plans for improvements to non-complying feeders. The new conditions require Integral Energy to complete actions to improve performance of non-complying feeders within a 9 month period.

2.2 COMPARISON WITH EXISTING INTEGRAL ENERGY POLICIES, STANDARDS AND PERFORMANCE

As part of the process of assessing the potential impact of the new licence conditions on Integral Energy, it is clearly necessary to compare the new licence condition requirements with those already established within the Integral Energy network business and also, where appropriate with the present, and forecast, network performance.

2.2.1 Integral Energy network strategy and approach to supply security

The Integral Energy strategic approach to managing its network is based on the management of a number of key indicators in an attempt to deliver the requisite level of service to connected customers. These key indicators include:

- the level of customer load at risk;
- asset age and condition; and
- network reliability performance.

The existing Integral Energy network strategy[37] is based on the principle of acceptance of a degree of risk – specifically, that the Integral Energy network will be designed, constructed and operated in the knowledge that not all of the customer load can be supported by the network at all times. Integral Energy believe that designing and operating a network which meets all of the load at all of the time at all levels on the network, is sub-optimal. An accepted level of load at risk is managed at sub-transmission and at distribution levels, on both substations and lines.

The Integral Energy existing strategy aims to contain customers' load at risk over the current regulatory period[38]. Table 2-4 shows the Integral Energy LAR target levels as submitted under the 2004 IPART determination.

As part of its network strategy for managing LAR, on hot days Integral Energy split the normally meshed 33kV, 66kV or 132kV networks in order to proactively manage any

37 Network Strategy, Integral Energy, March 2003.

38 The 'base case strategy'.

outage contingencies such as to minimise the scale and (electrical) extent of any potential impact on the sub-transmission network.

Sub-transmission lines

Under the existing investment plans, over the current regulatory period[39], Integral Energy aim to accept (and manage) an average LAR level of 373MVA[40] on sub-transmission lines. Integral Energy plan to reduce this managed level of LAR on sub-transmission lines down to around 30% of the present period average[41] by the end of the next regulatory period[42].

Substations

Integral Energy estimate the present level of LAR on substations to be 539MVA. Existing investment plans aim to (approximately) maintain this level of LAR over the current regulatory period[43]. Integral Energy plan for the LAR on substations to remain at approximately 500MVA over the next regulatory period, although the existing plans are shown to significantly reduce LAR towards the end of the next period (2013/14)[44].

Distribution feeders

As for sub-transmission lines and major substations, the Integral Energy approach for the management of load security on distribution circuits is to adopt and manage an acceptable level of LAR. Integral Energy's present approach is to target a limit on the number of distribution feeders having LAR to approximately 30% of all circuits. This target presently extends to the end of the next regulatory period.

In its high-level, long term, planning analysis, Integral Energy assumes that the average rating of a distribution feeder is 300A. It is further assumed that this is a summer rating and that the peak loading on distribution feeders occurs during the summer months. To allow for a forced outage of a critical network element[45], Integral Energy assign a firm rating to distribution feeders equal to 80% of the summer conductor rating[46]. Distribution feeders carrying more than 240A are therefore considered overloaded and having a degree of LAR.

The number of overloaded distribution feeders each year, and the extent to which this number changes, is determined by both the underlying increase in overloaded feeders[47] (primarily as a result of load growth) and the number of overloaded feeders which are

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39 The 'current' regulatory period is from 1 July 2004 to 30 June 2009.

40 'Major Projects LAR calculation samp draft 11 ipart.xls' – revised versions, as provided to PB Associates by Integral Energy on 6 October 2005).

41 The (existing) planned LAR level for sub-transmission lines by 2013/14 is 116MVA.

42 The 'next' regulatory period is from 1 July 2009 to 30 June 2014.

43 Integral Energy estimate the LAR on substations to average 584MVA over the current regulatory period (under June 2009).

44 The step reduction in LAR at the end of the next regulatory period is largely due to Integral Energy's expectation that load on a number of new and converted major substations will have been fully transferred by the end of the period.

45 The highly interconnected nature of the Integral Energy distribution network means that existing feeders under normal running conditions are permitted to operate at 4/5 of the their summer rating. This is based on the assumption that the load on a single circuit can be shared between four adjacent (electrically parallel) circuits in the event of a forced (unplanned) outage.

46 Distribution feeders loaded in excess of 240A are therefore considered to have customer load at risk.

47 Integral Energy assume an underlying increase in the number of distribution feeders of 25 per year.

rectified via investment activity and other work programmes. The three ways in which Integral Energy addresses overloaded distribution feeders are:

- distribution network reinforcement associated with major project schemes;
- specific distribution works programmes; and
- distribution feeder augmentation associated with new customer network connections.

Table 2-4 – Integral Energy LAR summary (under existing plans[48])

Year	*Sub-transmission line LAR*	*Substation LAR*	*Number distribution feeders with LAR*
2004/05	323	539	360
2005/06	468	702	349
2006/07	401	605	333
2007/08	327	502	292
2008/09	347	571	290
2009/10	294	528	306
2010/11	176	512	293
2011/12	137	463	302
2012/13	164	479	317
2013/14	116	198	336

2.2.2 Design planning criteria (network security)

The Integral Energy network planning policy[49] sets out the supply security standard for both the sub-transmission and distribution networks. The Integral Energy standards are based on credible contingencies; these include the potential loss of key network elements such as transformer units, lines and cables. The defined credible contingencies align with national and internal convention and practice.

The design planning standards included in the new licence conditions are very similar to the existing Integral Energy design planning standards[50]. The notable exception, and driver behind a potential increase in the required level of network investment in the current (and next) regulatory period, is the timetable for compliance and, some instances, the difference in the approach to the ongoing management of customer load at risk.

48 Existing plans are those as submitted to IPART as part of the 2004 price control review.

49 Network Asset Management, Document No. 9.2.1, Amendment 4, Integral Energy.

50 The new licence conditions include, for Integral Energy, a relaxation of the 5MVA load threshold to 10MVA – effective until 2014. The 10MVA threshold aligns with the existing Integral Energy planning policy.

The main difference between the existing Integral Energy design planning policy and that imposed under the new licence conditions is that the new arrangements require:

- all sub-transmission lines to operate with no LAR as of 1 July 2009;
- LAR associated with all sub-transmission substations to be eliminated by 2012;
- LAR associated with distribution feeders supplying large urban towns to be eliminated by 2014; and
- LAR associated with all large zone substations (>20MVA[51]) to be eliminated by 2019.

Until these future compliance dates, the new licence conditions provide for an acceptance of a degree of load at risk[52]. The existing Integral Energy design planning policy is targeted to give rise to a similar outcome for LAR but for an indefinite period.

The existing Integral Energy network development strategy and planning policy would appear to adequately support the design planning criteria in the new licence conditions requirements in all other respects.

2.2.3 Reliability standards (SAIDI, SAIFI)

The existing Integral Energy business practices systems already measure, record and report SAIDI and SAIFI network reliability standards. There is a requirement to regularly report the network performance figures to IPART and to publish the network reliability performance on an annual basis as part of a network performance report[53].

Although, a prima facie assessment might suggest that the performance standards in the new licence conditions are comparable with the existing Integral Energy network performance standards, there are differences in the exclusion methodology used in the two methods.

The new licence condition reliability standards provide for the exclusion of ‘major event days’. The imposed reliability standards defined a ‘major event day’ in accordance with the IEEE standard[54]. Under the new standards, the threshold value (used in the process of identifying major events) is calculated using a statistical method known as the *beta method*.

Integral Energy’s existing reliability performance figures also provide for the exclusion of major events, but uses a different methodology for identifying, and excluding, major event days. The existing approach for exclusion employed by Integral Energy is as defined by the Steering Committee for National Regulatory Reporting Requirements (SCNRRR).

In comparing the ‘beta method’ and the SCNRRR approach used by Integral Energy, the use of the beta method is likely to result in a fewer number of excluded events. However, the ‘beta method’ also allows for the exclusion of extreme outage due to network related events – in addition to the exclusion of third party events and major natural occurrences.

51 PB Associates is not aware of the definition of the 20MVA threshold in the but assume that this associated with firm transformer capacity.

52 In accordance with the 1% LAR criterion.

53 Electricity Network Performance Report 2003/2004, Integral Energy.

54 IEEE Standard 1366-2003 for Electric Power Distribution Reliability Indices.

2.2.4 Individual feeder performance

Integral Energy has a policy of addressing poorly performing feeders and an existing programme of works. This includes installation of new distribution feeders, reconfiguring of existing network arrangements and the installation of auto-reclosers and other system automation. The new individual feeder new licence conditions will require a number of individual improvement schemes to be advanced.

3. REVIEW OF THE INTEGRAL ENERGY APPROACH TO THE ASSESSMENT OF COSTS

In this section of the report we describe the approach taken by Integral Energy in estimating the impact on capital expenditure of compliance with the new licence conditions. This includes a review of each element of the new licence conditions – design planning, reliability standards and individual feeders performance.

In order to fully understand the approach adopted by Integral Energy we also undertook a review of a selection of projects and the treatment of each of those investments by Integral Energy in its impact assessment. These project reviews are included at the end of the section.

3.1 DESIGN PLANNING (SECURITY)

The main differences between the existing Integral Energy design planning policy and that imposed under the new licence conditions are set out in Section 2.2.2 of this report.

The network design planning criteria under the new licence conditions have a high degree of alignment with the existing Integral Energy planning policy. The principal differences lie in the management of load-at- risk (LAR), specifically, the time period over which LAR, for various network elements, is reduced to a prescribed level or eliminated altogether.

3.1.1 Load at risk (standards and assessments)

The Load at Risk (LAR) is defined as the load that may be required to shed in case of a single component failure where n-1 security condition is imposed. It is essentially the difference between the electrical load and the maximum supportable load following a credible contingency.

The approach adopted by Integral Energy to assess LAR is to compare the forecast demand with the existing or planned capacity increases. In order to correlate the incidence of expenditure with the availability of network capacity, Integral Energy has assumed that the additional new capacity becomes available once 95% of the investment has been made. This approach is adopted for both sub-station and line capacity increases.

It is not always straightforward to estimate LAR at the planning stage due to the variation in peak demand times for various feeders and substations. The approach taken by Integral Energy is to assess the likely LAR outcome for each (relevant) asset and to develop an investment plan which aims to confine these LAR events to within the 1% limit. The resulting individual estimates of LAR exposure, based on the planned investment programme and forecast peak loads, are aggregated to arrive at an overall LAR figure[55].

Integral Energy has advised PB Associates that they do not specifically target a total LAR amount, but instead plan to mitigate the LAR events in accordance with the 1% probability requirement[56].

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55 Although a ‘total system’ LAR number is determined as the simple sum of the individual substation LAR exposure levels, this total would appear to have little practical relevance and is used for definitional convenience.

56 Integral Energy considers that the LAR value is an outcome of the planning process, not a leading indicator that (by itself) drives investment.

Table 3-1 – Integral Energy proposed LAR outcome under new licence conditions

Year	*Sub-transmission line LAR*	*Substation LAR*	*Number distribution feeders with LAR*
2004/05	323	539	360
2005/06	479	763	349
2006/07	414	667	333
2007/08	291	426	292
2008/09	0	378	278
2009/10	0	247	250
2010/11	0	197	205
2011/12	0	174	154
2012/13	0	219	109
2013/14	0	163	62

3.1.2 Sub-transmission lines

The new licence conditions mandate that all LAR associated with sub-transmission lines must be eliminated as of 1 July 2009. This is shown Table 3-1 as a target of zero LAR 2008/09 onwards.

The approach of Integral Energy is to advance (in time) all of those projects on the investment planning time horizon associated with augmentation of the sub-transmission network – so as to eradicate LAR by 2009.

From its review of the Integral Energy strategic asset management plan (SAMP), PB Associates is not aware of any sub-transmission lines which are forecast to have LAR by 2009 where there is not a plan to eliminate the LAR before the end of the next regulatory period[57].

The Integral Energy assessment of advancement of investments does not consider the potential for resource constraints or other internal organisational challenges or the prospect of any logistical interdependences.

3.1.3 Substations (sub-transmission, zone)

The new licence conditions prescribe LAR levels for both sub-transmission and zone substations. All LAR associated with all sub-transmission substations must be eliminated by 2012. All LAR associated with all large zone substations (>20MVA[58]) must be eliminated by 2019. In both cases LAR is permitted, until the time specified for

57 PB Associates has been provided with the Integral Energy existing (IPART) strategic asset management plan (SAMP) which provides details of the planned capital expenditure levels from 2005 to 2015.

58 PB Associates is not aware of the definition of the 20MVA threshold in the but assume that this associated with firm transformer capacity.

compliance, where the probability is less than 1% that load may not be able to be sustained following a failure.

Monitoring and management of LAR is an important element of the existing Integral Energy asset management strategy and plays a key role in the prioritisation of the network investment plan – in terms of the timing of major projects.

The Integral Energy approach to assessing the impact of the imposed LAR levels at substations is to quantify the cost of advancing major works associated with reducing, or eliminating, LAR – as required. Integral Energy has developed spreadsheets to estimate the LAR permitted by imposition of the 1% LAR threshold. The approach taken by Integral Energy comprise two elements:

- translation of the 1% threshold into a corresponding MVA LAR level; and
- advancement of the required major projects to ensure that the LAR limits are achieved.

Translation of the 1% LAR standard

PB Associates understands that during the commentary period for the new licence conditions, the Ministry confirmed that the definition in the new licence conditions is an adaptation of the existing Integral Energy design planning standard[59]. In this Integral Energy planning policy, the 1% criterion is further qualified to clarify that '*four days in any 12 month period equates to a nominal 1% of the calendar year'* [60]*.*

Given this interpretation, the Integral Energy approach as been as follows:

- take the peak (annual) demand at each substation;
- sum the difference between the peak demand and the firm capacity at each substation where the difference is positive (i.e. load exceeds capacity);
- repeat for each substation for the second highest peak day;
- repeat for third four and fifth highest days; and
- If LAR exists on the fifth day, then investment is triggered to mitigate against this LAR[61].

Under the Integral Energy interpretation and methodology, the sum of the individual LAR figures at each substation on the fifth highest demand day (at each substation) indicates the expected LAR level resulting from application of the 1% threshold in the new licence conditions.

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59 Network Management Policy 9.2.1 Network Planning, Integral Energy.

60 PB Associates notes that the new licence conditions do not include this qualifying statement and that, as presently drafted, the LAR threshold could be interpreted differently. For the purposes of this assignment, and in assessing the reasonableness of the Integral Energy approach to the assessment of the cost implications, PB Associates has taken the Integral Energy interpretation of the 1% LAR definition. PB Associates notes that whilst this may be the most straightforward interpretation, and potentially the most reasonable in terms of practical assessment, it is not the only interpretation of the 1% LAR criterion. Further consideration and/or analysis of the 1% threshold figure is outside the scope of this report.

61 The investment aims to reduce the (aggregated) duration for which customer load is at risk (in accordance with the 1% threshold) and not necessarily the magnitude of the LAR within this time period.

Advancement of major projects

Integral Energy has therefore advanced a number of its major projects in order to ensure that total LAR associated with its sub-transmission substations is eliminated by 2012 and that LAR associated with zone sub stations, and all sub-transmission substations ahead of 2012, remains below the 1% threshold.

Table 3-2 compares the LAR forecast profile associated with Integral Energy's existing investment plan and that associated with the modified plan for licence compliance.

In determining which major projects to advance in order to comply with the new substation LAR requirements, Integral Energy adopts the following prioritisation hierarchy:

1. those projects associated with addressing the highest levels of LAR

2. green field development sites

3. existing (or 'brown-field' sites)

This methodology has been used by Integral Energy to assess which projects are advanced, and hence those that form the basis for the additional costs of compliance in the present regulatory period.

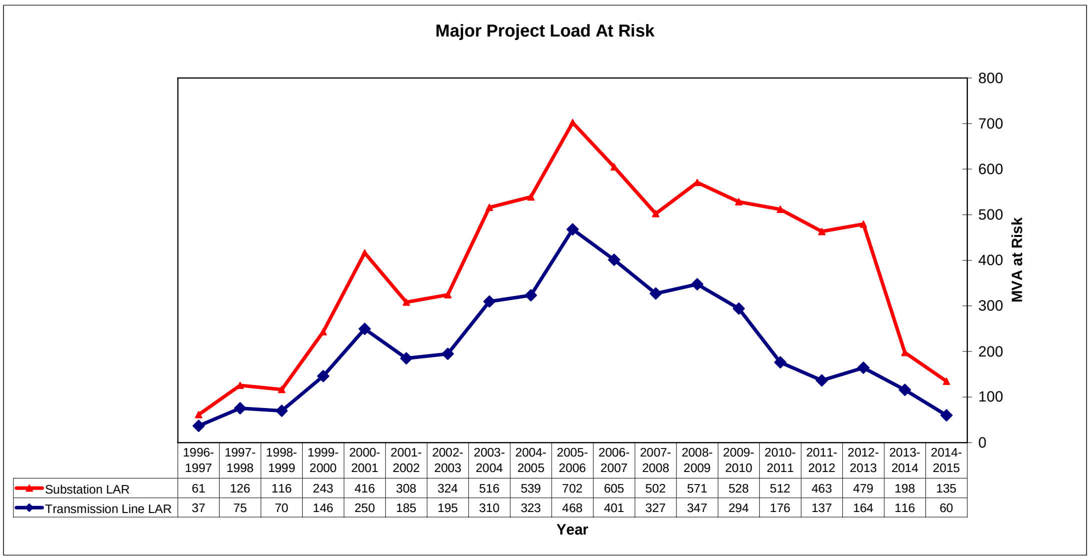
The Integral Energy investment plan also reflects the removal of the relaxation on load magnitude (10MVA to 5MVA) at June 2014.

Table 3-2 – Comparison of forecast substation LAR

Year	Existing (IPART)	New conditions (DEUS)
2004/05	539	539
2005/06	702	763
2006/07	605	667
2007/08	502	426
2008/09	571	378
2009/10	528	247
2010/11	512	197
2011/12	463	174
2012/13	479	219
2013/14	198	163

Figure 3-1[62] shows the actual LAR associated with sub-transmission substations and lines over the period 1996-97 to present along with the project LAR in accordance with the existing Integral Energy strategic asset management plan over the period to 2014/15.

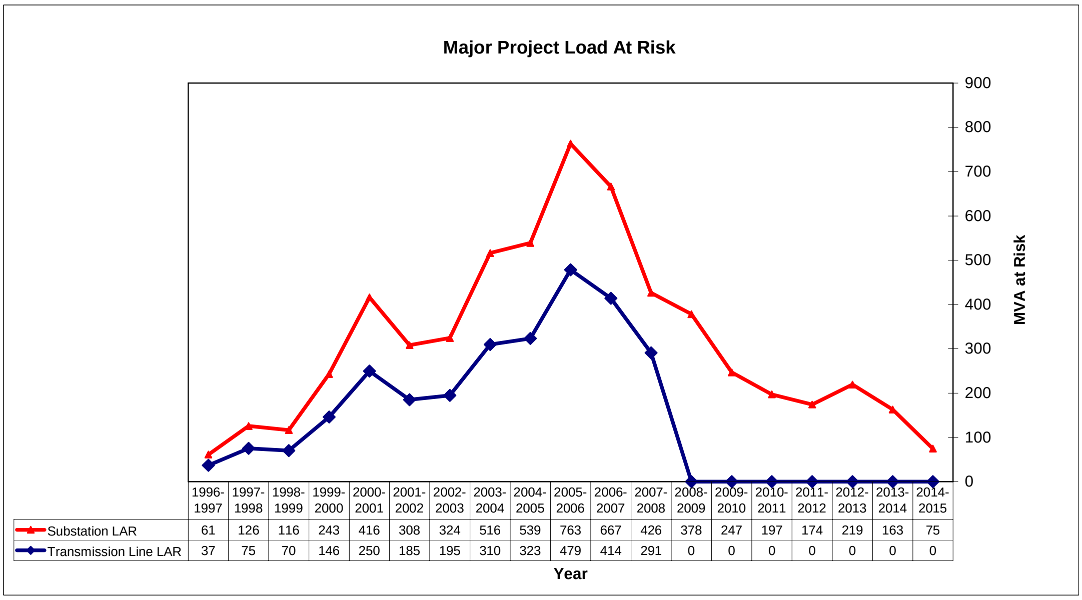
Figure 3-1 – Substation and transmission line LAR under the existing capex plan



Year	1996-1997	1997-1998	1998-1999	1999-2000	2000-2001	2001-2002	2002-2003	2003-2004	2004-2005	2005-2006	2006-2007	2007-2008	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015
Substation LAR	61	126	116	243	416	308	324	516	539	702	605	502	571	528	512	463	479	198	135
Transmission Line LAR	37	75	70	146	250	185	195	310	323	468	401	327	347	294	176	137	164	116	60

Figure 3-2 shows the LAR profile associated with the Integral Energy interpretation of the new design planning requirements. The elimination of all LAR associated with sub-transmission lines by 2009 is evident in the chart. All of the LAR on substations post 2012 is associated with zone substations. Integral Energy have estimated this to reduce to approximately 75MVA by 2014/15.

Figure 3-2 – Substation and transmission line LAR under the revised capex plan



Year	1996-1997	1997-1998	1998-1999	1999-2000	2000-2001	2001-2002	2002-2003	2003-2004	2004-2005	2005-2006	2006-2007	2007-2008	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015
Substation LAR	61	126	116	243	416	308	324	516	539	763	667	426	378	247	197	174	219	163	75
Transmission Line LAR	37	75	70	146	250	185	195	310	323	479	414	291	0	0	0	0	0	0	0

62 Charts provided by Integral Energy.

3.1.4 Distribution

The new licence conditions mandate that the LAR associated with distribution feeders supplying large urban towns must be eliminated by 2014.

In assessing the impact of the new licence conditions on distribution feeders costs, Integral Energy has taken account of the distribution network LAR conditions which are rectified as part of a major project (which may itself have been advanced to fulfil new substation LAR requirements)[63]. With the number of new network connections assumed to be outside of the control of Integral Energy, the outstanding distribution feeders, having a higher than required LAR, are addressed through an increase in the (separate) distribution works programme.

In order to determine the number of overloaded distribution feeders, Integral Energy adopt the following approach:

- take the existing number of feeders having a summer rating of in excess of 240A[64];
- subtract the number of overloaded feeders addressed by:
  - major works;
  - new customer connections;
  - general distribution work programmes ;and
- add 25 feeders per year growth.

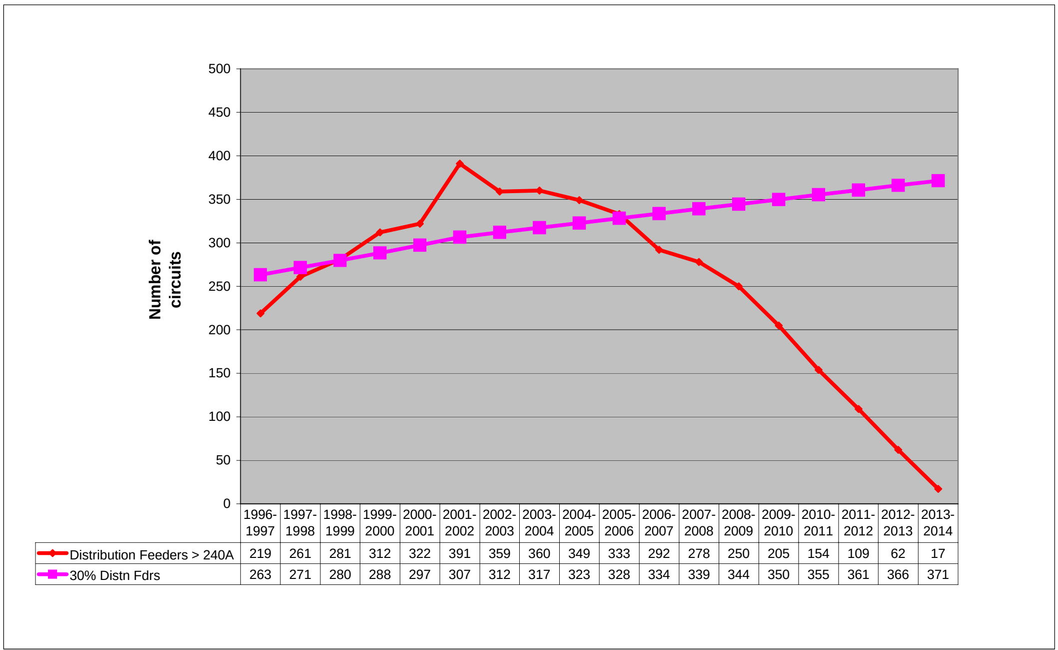
In assessing the total cost of this additional distribution works Integral Energy has applied an average cost per feeder of $500,000.

The forecast number of distribution feeders having LAR under the revised investment plan is shown in Figure 3-3. This is the Integral Energy assessment of the investment needed to comply with the requirement for there to be no LAR associated with distribution feeders supplying large urban towns by 2014.

63 A example of this may be where the construction of a zone substation serves to reduce 11kV feeder lengths and reduce 11kV feeder loading in the locality of the new substation.

64 Integral Energy presently assesses this to be 391.

Figure 3-3 – Overloaded distribution feeders under revised investment plan



3.1.5 Integral Energy assessment

Integral Energy's revised capital expenditure plan for compliance with the new design planning conditions is given in Table 3-3[65].

Table 3-3 – Revised capex for compliance with new design planning conditions

	2004/05 ($m) [66]	*2005/06 ($m)*	*2006/07 $m)*	*2007/08 ($m)*	*2008/09 ($m)*	*Total ($m)*
Original plan (IPART)[67]	236.19	262.52	241.36	243.26	204.61	1,187.94
Revised plan (DEUS)	195.60	263.56	324.16	331.38	401.94	1,516.64
Variation	-40.59	1.04	82.80	88.12	197.33	328.70

65 It should be noted that the revised capital plan includes programmes of work which will improve general reliability performance, however these numbers exclude the estimated additional capital expenditure required to comply with the new individual feeder standards. This additional expenditure is set out in Section 3.3.1 of this report.

66 2004/05 dollars (real).

67 These numbers are the final IPART 2004 Determination totals minus the reliability improvement expenditure element of the 2004 submission (adjusted to reflect the Determination outcome). From Integral Energy spreadsheet '010 IPART 2004 Determination allowances tc.xls' as provided to PB Associates by Integral Energy on 8 November 2005 and 'RIP-Budget-Draft2.xls', sheet 'Summary' as provided to PB Associates by Integral Energy on 17 October 2005.

3.1.6 PB Associates observations and comment

PB Associates has undertaken a review of the approach undertaken by Integral Energy in assessing this cost impact of compliance with the new design planning standards. In general, we are in agreement with the Integral Energy assessment that the principal consequence of compliance with the security standards is to advance in time, a number of projects already identified in the Integral Energy strategic asset management investment plan.

One observation, however, is associated with the principle of advancing augmentation works in a climate of an increasing trend in system load.

As an example, consider the case where a system augmentation investment, originally planned to occur in 2015, is advanced by 9 years in order to fulfil the requirement to eliminate LAR in 2006 – as shown in Figure 3-4[68]. Whilst the capacity increase at 2015 is appropriate to eliminate LAR, and provide a reasonable capacity headroom at 2015, the capacity headroom this same investment provides at 2006 might be considered to be more than reasonably required. In theory, there may, therefore, seem to be an opportunity to defer some of this additional capacity investment at 2006 until a later time (e.g. 2015)[69].

Whilst we acknowledge that it is generally accepted planning practice to adopt a 10 year planning horizon, and as such it may be reasonable to implement augmentation solutions which consider the system loading conditions 10 years out, we also believe that, where possible, investment decisions should be made so as to minimise the net present cost.

Economies of scale (and scope) and indivisibilities of augmentation solutions (i.e. lumpiness of plant and equipment) are likely to limit the opportunities for deferral of this kind, but PB Associates would recommend that Integral Energy reviews its major investment plans to confirm this to be case.

Subject to this observation, and given the scope of the review assignment, PB Associates believes that the method employed by Integral Energy in arriving at this additional level of expenditure is reasonable.

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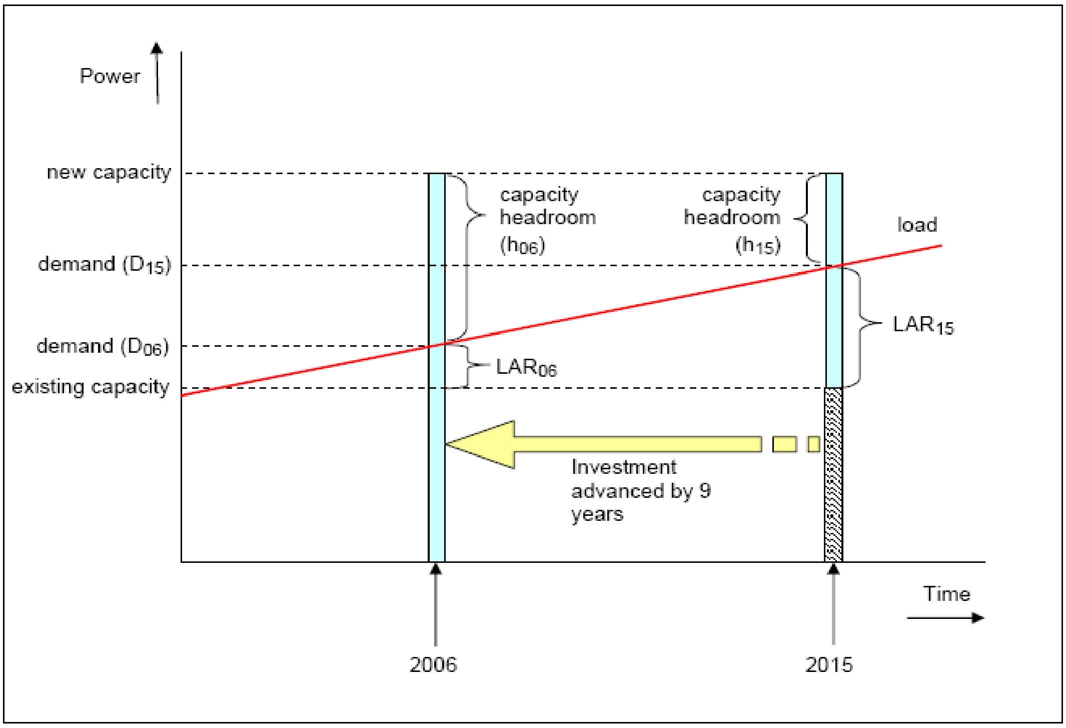
68 Note that the load growth line and capacity increments may be exaggerated and are for illustrative purposes only.

69 For example, in Figure 3-4, the capacity could be increased by an amount, say, equal to (D_{15}-D_{06}) and then again by an amount equal to H_{15} 2015 – rather than by the entire amount (D_{15}-D_{06}+H_{15}) at 2006.

Figure 3-4 – Advancing reinforcement works in a climate of increasing system load



Distribution works feeder costs

In costing the expenditure impacts of the requirement for distribution feeder reinforcement work, Integral Energy use a figure of $500,000. Information presented by Integral Energy to PB Associates provides an average cost figure of $377,000 for distribution feeders works. This is based on outturn costs for a representative selection of historic projects.

Given the uncertainty associated with the extent and scope of forthcoming distribution feeder investments, together with the prospect of an increase in the cost per unit of output (network performance) as the more cost effective opportunities are exhausted, we do not believe that the $500,000 figure used is an unreasonable basis for the purpose of developing forward-looking planning estimates in the context of this impact assessment exercise.

3.2 RELIABILITY STANDARDS (SAIDI, SAIFI)

This section reviews the Integral Energy approach to the assessment of the cost impact of the mandated reliability requirements.

3.2.1 Integral Energy assessment

Integral Energy has undertaken analysis to convert its existing (SCNRRR-based) SAIDI and SAIFI targets into 'beta method equivalent' targets. Actual performance information has been used to calculate the difference between the SAIDI and SAIFI values using both methods. An adjustment factor, based on a three-year[70] historic average, has been used to adjust the existing reliability performance forecast to reflect the beta method used in the new licence condition standards.

70 Actual reliability information for 2002/03, 2003/04 and 2004/05.

3.2.2 PB Associates observations and comment

PB Associates has reviewed the results of the Integral Energy comparison between the existing and the new standard. We have not reviewed the calculations or analysis undertaken by Integral Energy to convert the existing standards (SCNRRR-based exclusion methodology) to the 'beta equivalent' targets. However, we support the methodology of using recent historic information to establish the relationship between the two sets of targets and use of this calibration factor to adjust projected targets for SAIDI and SAIFI.

The forecast network reliability targets for Integral Energy using this approach suggest that the new licence conditions are unlikely to require a fundamental change in Integral Energy's approach to total system reliability performance management. Hence, the additional capital expenditure required to fulfil this aspect of the new conditions is expected to be minimal, and Integral Energy has not required these potential impacts to be assessed in this review.

3.3 INDIVIDUAL FEEDER PERFORMANCE

Integral Energy has assessed the potential cost impact of the new reliability requirements associated with individual feeders.

3.3.1 Integral Energy assessment

Integral Energy has an existing planned programme of reliability improvements which focuses on poorly performing part of the network. PB Associates has been advised that a capital expenditure level totalling $36m[71] has been nominally allowed within the 2004 determination to address reliability improvements over the present regulatory period.

From its prioritised list of reliability improvement projects, Integral Energy has identified the additional works required to ensure that the prescribed minimum individual feeder standards[72] are met for each remaining year of the present regulatory period. The estimation of the additional required expenditure amount has been adjusted to account for projects underway in, or programmed for, 2005/06.

Integral Energy's revised capital expenditure plan for compliance with the new individual feeder standard is given in Table 3-4.

71 2004/05 dollars (real)

72 As set out in Table 2-3 of this report.

Table 3-4 – Revised capex for compliance with new individual feeder standards

	2004/05 ($m)[73]	2005/06 ($m)	2006/07 $m)	2007/08 ($m)	2008/09 ($m)	Total ($m)
Original plan (IPART)[74]	7.20	7.20	7.20	7.20	7.20	36.00
Revised plan (DEUS)	7.20	9.46	12.53	12.59	10.84	52.62
Variation	0.00	2.26	5.33	5.39	3.64	16.62

3.3.2 PB Associates observations and comment

From its prioritised plan of individual distribution feeder works, Integral Energy has estimated that an additional $16.6m is required to comply with the minimum individual feeder standards. This comprises additional expenditure to trial new equipment and software, additional automation and research and survey activities at sub-transmission substations.

PB Associates has been provided with information showing the Integral Energy reliability improvement budget[75]. With regard to the distribution reliability works, this information is limited to a list of the planned reliability projects, appropriately ranked in terms of improvement priority. The information provided to PB Associates shows the Integral Energy planned timing of each project in order to comply with the new licence reliability standards. PB Associates has not been provided with details of the rationale underlying these precise timings, nor details of the basis for the absolute expenditure levels. However, we observe that the incidence of planned expenditure would appear to be targeted at remedying the worst performing feeders first.

It should also be noted that PB Associates has not reviewed the basis for, or estimation of, the anticipated improvement in SAIDI and/or SAIFI performance. Nevertheless, we believe that the methodology of compiling an investment plan based on a ranked list of poorly performing feeders offers a sound approach for quantifying the additional expenditure required for compliance with the prescribed standards.

3.4 DETAILED PROJECT REVIEW

As part of the PB Associates assessment of the Integral Energy approach to quantifying the impact of the new licence requirements, we undertook a review of a number of carefully selected projects. All of the selected projects involved major project investments.

73 2004/05 dollars (real).

74 These numbers are the reliability improvement expenditure element of the 2004 submission (adjusted to reflect the Determination outcome). From Integral Energy spreadsheets 'SAMP-2005-2015-draft 11 ipart.xls, sheet 'Summary tables' as provided to PB Associates by Integral Energy on 6 October 2005 and 'RIP-Budget-Draft2.xls', sheet 'Summary' as provided to PB Associates by Integral Energy on 17 October 2005.

75 RIP-Budget-Draft2.xls', sheet 'Summary' as provided to PB Associates by Integral Energy on 17 October 2005.

3.4.1 Objective

The purpose of the individual project review is to understand the rationale behind proposed changes to the capital expenditure profile and to confirm that this is the direct result of the need to comply with the new licence requirements.

The earlier works programme which was submitted to IPART consists of several hundreds of projects. According to Integrals Energy's latest information many projects will need to be brought forward. On this basis, we have selected 10 specific projects from the programme on the basis of capital expenditure amount and type of work involved for our scrutiny.

Total capital cost of each project has been without any investigation on the basis that they have already been accepted in the previous programme which was submitted to IPART. Technical justifications for all committed projects are available on the NEMMCO website. However, the projects that need to be brought forward do not have similar forms of technical justifications or project documents. However, a spreadsheet that details present and future feeder/substation capacities and expected demand growth with figures of Load At Risk (LAR) was made available to PB Associates for our scrutiny.

3.4.2 The selection of projects and programmes

PB Associates undertook a simple comparison of the expenditure incidence in the existing Integral Energy strategic asset management plan with that in the investment plan amended to fulfil the revised standards. From this resulting list of major projects whose expenditure profile had changed, we selected eight investment schemes. The selection of projects was not entirely random but based on the capital expenditure amount and the type of work involved.

The following list of programmes/projects selected for PB Associates review.

1. West-ADI 33/11kV zone substation establishment (PR342)
2. Southwest sector additional works (PR289)
3. Summer power factor correction capacitors (PR063)
4. Russell Vale (PR061)
5. Split 804 tee to Wentworth Falls and Wentworth Falls ZS augmentation (PR099)
6. Feeder 7050 and 7043 augment from Mt Terry to Jerrara (PR195)
7. Rebuild feeder 455 to 132kV operation (PR033)
8. Shoalhaven feeder 7503/7506 augment (PR355)

For each of these selected projects we:

- reviewed the existing investment timings (IPART plan);
- considered the implications of the new licence conditions; and

A summary of these reviews is provided below, together with the PB Associates comments on the Integral Energy assessment.

3.4.3 Project 1 – West-ADI 33/11kV zone substation establishment (PR342)

Penrith TS has three 60MVA 132/33kV transformers with provision for a fourth. The substation firm capacity of 138MVA is limited by the breakers and isolators on 33kV side of the transformers. The diversified summer demand forecast for the substation is already higher than its firm capacity. Augmentation of this substation is a necessity to avoid load shedding at peak hours. The project has a total cost of $12m.

Existing investment plans/timings (IPART)

This project was not included in the capital works programme (2004-2014) which was submitted to the IPART as part of the 2004 determination. Integral Energy was prepared to accept a level of load at risk on this sub-transmission substation.

Implications of new Licence conditions (DEUS)

According to the relevant project report it is imperative that this project is completed by the year 2012 to meet the new licence conditions. The project is scheduled to take three years to complete with a capital expenditure profile of $1m, $3m and $8m respectively. The new licence conditions require Integral Energy to advance this capital expenditure of $12m in order to eliminate LAR under n-1 security criteria. This requirement is in the next regulatory period (2009/10 to 2013/14) and so does not impact on expenditure in the current period.

Observations and comments on Integral Energy assessment

From the information reviewed, PB Associates believes that all credible load transfers have been considered and that the investment timing is reasonable Full utilisation of the project is heavily dependent on a number of related sub-projects. Overall, technical justification and timing of the project seems to be satisfactory.

3.4.4 Project 2 – Southwest sector additional works (PR289)

The Integral Energy project documentation reviewed by PB Associates outlines a proposed network configuration suitable to accommodate a totally new residential and industrial development in the South West Sector. According to the report electricity demand of 37MVA from the development will be imposed on the network as early as 2006/2007. The project proposes 12 new zone substations, interconnecting sub-transmission lines and augmentation to the existing network with a total estimated cost of $268m. High level demand estimation was undertaken and contingencies have been considered using load flow studies.

Existing investment plans/timings (IPART)

This project was not included in the capital works programme (2004-2014) which was submitted to the IPART as part of the 2004 determination.

Implications of new Licence conditions (DEUS)

Under the new licence conditions the project will commence in the 2007. Investment will ramp up until the end of the present regulatory period and is planned to continue at $50m per annum throughout the next regulatory period. $18.0m of the total investment falls into the current regulatory period with the remaining $250m in the following period.

Observations and comments on Integral Energy assessment

We understand that this project has now been confirmed as a result of a firming of DIPNR plans for additional housing. The project cost estimates appear to be based on broad estimates. PB Associates is unable to justify full expenditure of $268m solely on the grounds of the new licence conditions. Furthermore, it may not be unreasonable to suggest that some of the additional $18m falling into the current period is due to external events and is not, therefore, attributable to the new licence conditions.

3.4.5 Project 3 – Summer power factor correction capacitors (PR063)

The aim of this project is to install switching type static reactive power compensators (capacitor banks) in zone substation in order to relieve reactive loading on sub-transmission lines and zone substation transformers. It is also proposed that overall losses and substation voltages will be improved.

Existing investment plans/timings (IPART)

According to the works programme that was submitted to the IPART, this project is to commence in the year 2008 and to be completed by the year 2012.

Implications of new Licence conditions (DEUS)

The installation of capacitors is to improve line loadings and voltage profiles. The new licence conditions have no impact on this proposed investment. This is confirmed by an identical expenditure profile in the existing and revised strategic asset management plan.

Observations and comments on Integral Energy assessment

PB Associates agree with the Integral Energy assessment.

3.4.6 Project 4 – Russell Vale (PR061)

Russell Vale zone substation is equipped with two 10MVA transformers connected in parallel, providing a continuous firm capacity of 10MVA. The demand forecast suggests that the substation firm capacity is well below the winter peak demand and marginally below the summer peak demand. By 2010 winter peak load will be 61% above the continuous firm capacity of the transformer.

Existing investment plans/timings (IPART)

Augmentation of this substation is to commence in the year 2007/2008 and to be completed in the year 2009/2010.

Implications of new Licence conditions (DEUS)

The existing project expenditure profile fulfils the new requirements.

Observations and comments on Integral Energy assessment

The material reviewed by PB Associates has not included information on project cost or provide detailed technical justification for the scheme. From the information reviewed the timing of the project would appear to fulfil the requirements.

3.4.7 Project 5 – Split 804 tee to Wentworth Falls and Wentworth Falls ZS augmentation (PR099)

As at present Wentworth Falls zone substation has only one 8/10MVA transformer and is fed from a spur line which is teed off from feeder 804. Neither the substation nor the feeder is able to offer firm capacity. The project comprises two phases; first is to split feeder 804 and to loop it in to the substation. The second is to augment the substation.

Existing investment plans/timings (IPART)

This work is due to commence in 2008/09 and is scheduled to be completed by 2009/10.

Implications of new Licence conditions (DEUS)

Under the new licence conditions the project is advanced by a year to meet the new feeder security conditions imposed by the new licence conditions. The additional cost implications due to new licence conditions are marginal.

Observations and comments on Integral Energy assessment

Some of the technical details associated with this project have not been reviewed by PB Associates. However, from the limited information reviewed, the timing appears to be correct.

3.4.8 Project 6 – Feeder 7050 and 7043 augment from Mt Terry to Jerrara (PR195)

Mt Terry sub-transmission substation has 2 x 120MVA 132/33kV transformers with a firm cyclic capacity of 156 MVA. The substation is fed via two 132kV feeders each having a rating of 343/392MVA (summer/winter). Feeders 98L & 98U emanate from Mt Terry providing supply to the Shoalhaven and the far south coast.

33kV feeders 7050 and 7043 will be overloaded from the year 2005 in case of an outage on other feeders that are connected to the Mt Terry transmission substation. This project is required as part of the investigation for the appropriate solution to the above constraint.

Existing investment plans/timings (IPART)

Investigations are to be carried out in the year 2008/2009 – in accordance with the previous plan which was submitted to the IPART.

Implications of new Licence conditions (DEUS)

The investigation is to be brought forward by a year under the new licence conditions to comply with the requirement to eliminate LAR. The cost implications are marginal.

Observations and comments on Integral Energy assessment

The suggested advancement by 1 year seems reasonable.

3.4.9 Project 7 – Rebuild feeder 455 to 132kV operation (PR033)

Feeders 450 and 455 exceed their thermal capacity in the summer of 2004/2005 for an outage of feeder 239 which is connected to Quakers Hill zone substation. This project is to upgrade feeder 455 and rearrange supply to Quakers Hill via 132kV.

Existing investment plans/timings (IPART)

This project is not in the existing investment plan.

Implications of new Licence conditions (DEUS)

The project is to be commenced and completed in the year 2008/09. The total expenditure of $1m is due to the LAR requirements under the new licence conditions.

Observations and comments on Integral Energy assessment

PB Associates is unable to comment on project cost in the absence of further detail. However timing of the project seems to be correct in order to meet new licence conditions by the year 2009.

3.4.10 Project 8 – Shoalhaven feeder 7503/7506 augment (PR355)

Feeders 7503 and 7506 from Shoalhaven to Nowra will exceed their thermal capacity by the year 2005 for an outage on the alternate feeder. This project will investigate upgrading options for these feeders.

Existing investment plans/timings (IPART)

Under the existing expenditure plan, the work is set to commence in 2009/10.

Implications of new Licence conditions (DEUS)

The study will commence one year earlier under the new licence conditions to comply with LAR requirements. Cost implications are therefore minimal.

Observations and comments on Integral Energy assessment

This project is part of other related project works aimed at meeting feeder security conditions imposed by the new licence conditions. Cost implications to Integral Energy are marginal.

3.4.11 Detailed project review conclusions

From the limited review of the selected major projects, PB Associates believes that Integral Energy has determined the cost implications of the new licence conditions in a manner which is consistent with its over-arching methodology of advancing projects in order to fulfil the mandated LAR requirements.

3.5 SUMMARY OF OVERALL COST IMPACT

Table 3-5 shows Integral Energy's estimation of the impact of compliance with the new licence conditions. The analysis undertaken by Integral Energy suggest that an additional total of $345m[76] will be required in the current regulatory period.

The vast majority of this additional expenditure is associated with compliance with the new design planning criteria – specifically, advancement of a significant number major projects and other distribution works in order to fulfil the LAR requirements.

Although revised capital plan includes programmes of work which will improve general reliability performance, Integral Energy has estimated the additional capital expenditure required to comply with the new individual feeder standards. This totals $16.62m over the regulatory period and is identified as a separate line item in Table 3-5.

76 2004/05 dollars (real).

Table 3-5 – Variation in total capex for compliance for new licence conditions

	2004/05 ($m)	2005/06 ($m)	2006/07 $m)	2007/08 ($m)	2008/09 ($m)	Total ($m)
IPART determination[77]	243.39	269.72	248.56	250.46	211.81	1,223.94
Revised plan (DEUS)[78]	202.80	270.76	331.36	338.58	409.14	1,552.64
Additional required reliability expenditure[79]	0.0	2.26	5.33	5.39	3.64	16.62
Total revised plan	202.80	273.02	336.69	343.97	412.78	1,569.26
Variation	-40.59	3.3	88.13	93.51	200.97	345.32

3.5.1 PB Associates observations and comment

The network design planning criteria under the new licence conditions have a high degree of alignment with the existing Integral Energy planning policy. The principal differences lie in the management of load-at-risk (LAR), specifically, the time period over which LAR, for various network elements, is reduced to a prescribed level or eliminated altogether. On this basis, we believe that the methodology employed by Integral Energy in arriving at the additional level of expenditure associated with design planning is reasonable.

77 From Integral Energy spreadsheet '010 IPART 2004 Determination allowances tc.xls' as provided to PB Associates by Integral Energy on 8 November 2005.

78 Ibid. Note that the 'Revised plan (DEUS)' figures include the reliability improvement expenditure element of the 2004 submission (adjusted to reflect the Determination outcome).

79 From Integral Energy spreadsheet 'RIP-Budget-Draft2.xls', sheet 'Summary' as provided to PB Associates by Integral Energy on 17 October 2005. This is principally the additional amount which Integral Energy estimate is required to comply with the new individual feeder standards.

4. CONCLUSION

Having undertaken this review of the approach adopted by Integral Energy in assessing the cost impact of the new licence conditions, PB Associates is able to draw the following conclusions.

Integral Energy's approach to assessing the cost impact is, in general, reasonable

The network design planning criteria under the new licence conditions have a high degree of alignment with the existing Integral Energy planning policy. The principal differences lie in the management of load-at- risk (LAR), specifically, the time period over which LAR, for various network elements, is reduced to a prescribed level or eliminated altogether. On this basis, the methodology and process adopted by Integral Energy in arriving at the additional level of expenditure associated with the new design planning criteria is not unreasonable.

Whilst we acknowledge that it is generally accepted planning practice to adopt a 10 year planning horizon, and as such it may be reasonable to implement augmentation solutions which consider the system loading conditions 10 years out, we also believe that, where possible, investment decisions should be made so as to minimise the net present cost. Consequently, although there are a number of factors which are likely to limit the opportunities for (part) deferral, PB Associates recommends that Integral Energy reviews the timing of its planned investments to confirm this to be case.

The majority of the estimated additional expenditure is for compliance with the new design planning criteria

The advancement of a significant number major projects and other distribution works, in order to fulfil the new LAR requirements, is responsible for the majority of the estimated additional costs.

The new reliability standards are likely to give rise to minimal additional expenditure

PB Associates has reviewed the results of the Integral Energy comparison between the existing and the new standard. We have not reviewed the calculations or analysis undertaken by Integral Energy to convert the existing standards (SCNRRR-based exclusion methodology) to the 'beta equivalent' targets. However, we support the methodology of using recent historic information to establish the relationship between the two sets of targets and use of this calibration factor to adjust projected targets for SAIDI and SAIFI.

The forecast network reliability targets for Integral Energy using this approach suggest that the new licence conditions are unlikely to require a fundamental change in Integral Energy's approach to total system reliability performance management. Hence, the additional capital expenditure required to fulfil this aspect of the new conditions is expected to be minimal, and Integral Energy has not required these potential impacts to be assessed in this review

The underlying principle applied by Integral Energy to assess the impact of the new individual feeder standards is sound

From its prioritised plan of individual distribution feeder works, Integral Energy has estimated the additional expenditure required to comply with the minimum individual feeder standards. This comprises additional expenditure to trial new equipment and software, additional automation and research and survey activities at sub-transmission substations.

PB Associates has not reviewed the underlying detail associated with individual project expenditures, nor the basis or estimation of the anticipated improvement in SAIDI and/or SAIFI performance. Nevertheless, we believe that the methodology of compiling an investment plan based on a ranked list of poorly performing feeders offers a sound approach for quantifying the additional expenditure required for compliance with the prescribed standards.

The individual project reviews confirmed application of the high-level approach adopted by Integral Energy

From the limited review of the selected major projects, PB Associates believes that Integral Energy has determined the cost implications of the new licence conditions in a manner which is consistent with its over-arching methodology of advancing projects in order to fulfil the mandated LAR requirements.

The Integral Energy assumptions associated the correlation of expenditure incidence with availability of new capacity are reasonable

In order to correlate the incidence of expenditure with the availability of network capacity, Integral Energy has assumed that the additional new capacity becomes available once 95% of the investment has been made. PB Associates believe this to be a reasonable assumption for the purposes of this assessment.