Jemena Electricity Networks (Vic) Ltd
Regulatory Proposal 2011-15

30 November 2009

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Overview

This regulatory proposal is the third submission that Jemena Electricity Networks (Vic) Ltd (**JEN**) and its predecessors have submitted to an independent economic regulator to establish its electricity distribution services and prices. It builds upon previous reviews with a number of substantial developments and increasing benefits to customers.

Earlier electricity distribution price reviews have established JEN's regulatory asset base, implemented performance incentives schemes, established ambitious efficiency expectations, and separated metering and public lighting assets into their own asset bases. This regulatory proposal now takes account of JEN's changing business environment and its plans to move forward and meet the challenges.

JEN's strategic objectives are to:

- *safety and environment* – prioritise health, safety & environment in everything JEN does
- *compliance* – meet all legislative, regulatory and duty of care obligations
- *prudent and efficient investments* – make prudent and efficient network investments that will deliver a satisfactory long term return on assets while delivering asset management plan commitments
- *community reputation* – protect and enhance JEN's reputation with the community, regulators and key stakeholders by striving for innovation, reliability, safety and excellent customer service in the face of increasing community expectations
- *financial viability* – seek to grow stable and sustainable profit and revenue streams in real terms to maintain both long and short term financial viability
- *manage risk* – establish and maintain a robust and transparent framework for the continual identification and management of technical and commercial risk
- *promote innovation* – develop network management plans that leverage off new technologies such as JEN's investment in advanced metering infrastructure (**AMI**) to enable more effective and efficient operation and network development, in addition to excellent customer service.

This regulatory proposal sets out how JEN will deliver these objectives in a prudent and efficient manner over the forthcoming regulatory control period.

Events and outcomes during the current regulatory control period

Corporate ownership

Singapore Power, a long term investor in energy infrastructure, now owns JEN through its subsidiary SPI (Australia) Assets Pty Ltd (**SPIAA**).

In 2006, the Australian Gas Light Company (**AGL**) and Alinta conducted a transaction that resulted in, among other things, Alinta taking ownership of AGL's Victorian electricity network and AGL retaining ownership of its retail arm. A year later, a consortium of Babcock and Brown and Singapore Power International (**SPI**) bought Alinta. Subsequently, SPI gained ownership of several of the former Alinta assets that now trade under the new Jemena brand. The largest of these include JEN, Jemena Gas Networks (NSW), Jemena Pipelines, and Jemena Asset Management.

Demand growth

The demand for electricity and the number of new connections to JEN's network has been broadly in line with the forecasts that the Essential Services Commission (**ESC**) determined and used to set JEN's prices for the current regulatory control period. Energy use by JEN's customers has grown a moderate 0.7 per cent since 2005, however peak demand has grown by 4.7 per cent to 2009.

Service performance

JEN's reliability performance over the current period has varied considerably in each year with an average decline. JEN has experienced considerable challenges in maintaining its network's reliability due to an increasing number of extreme weather events—storms, drought and bushfires—and increasing asset failures, many of which are also age related.

Expenditure

JEN has achieved operating cost efficiencies greater than those the ESC forecast in its 2005 decision. JEN expects to incur operating expenditure (**opex**) over the current regulatory control period of $254.3 million, which is 16.9 per cent below that allowed by the ESC after adjustment for growth and capitalisation policy.

JEN has met its commitment to invest in capital works that extend the life and capacity of its network, and to maintain reliability using innovative solutions, many designed to defer more major reinforcements and contain expenditure. Over the current regulatory control period, JEN expects to invest $377.2 million, which is 34.9 per cent higher than the amount the ESC allowed in 2005.

Of particular note is JEN's significant investment in demand related reinforcements including constructing two new zone substations and various high voltage augmentations.

Outsourcing

As part of the SPIAA group of companies, JEN has for many years had the benefit of outsourcing a large proportion of its asset management service to Jemena Asset Management (**JAM**, formerly Agility), a leader in the electricity industry.

During 2009, JEN's management conducted a service model project. The objective of the project was to establish a formal asset management agreement (**AMA**) under which JEN can continue to procure asset management services at an efficient level of cost and with incentives aligned to ensure ongoing service and cost performance.

JEN initiated bilateral negotiations with JAM to develop their new AMA. The negotiation framework applied the same controls for competitively tendering work. The resultant agreement, which will come into effect from 1 January 2010, creates a number of valuable outcomes for JEN:

- services and accountabilities are more clearly defined
- costs are transparent
- JAM has strong incentives to ensure it delivers JEN's required services at the lowest sustainable cost and in a manner that enables JEN to respond to its service incentive scheme
- risk is allocated to the party that can best manage it
- JEN has certainty of asset management resourcing, at least until the end of 2018.

JEN's changing business environment

JEN is facing a changing business environment.

Climate change

Recent climatic events experienced in Victoria such as extreme heat-waves, unprecedented drought, stronger storms and more intense bushfires, further substantiate the reality of climate change and the need for network businesses to manage and adapt their networks to these changing conditions.

Policies that influence generation and end use

The Australian Government has a stated intention to implement carbon pricing and trading, and other new policies—such as advanced metering infrastructure, renewable energy targets and a government initiative to phase out greenhouse intensive hot water systems—that will significantly influence how customers use electricity and the emergence of renewable sources, and will change JEN's market trends and costs.

New regulatory developments

Several new market and regulatory developments will come into effect after JEN has lodged this proposal: the national energy customer framework, the national framework for electricity customer connections, and the national framework for electricity planning and expansion. As the additional costs JEN will incur to comply with its obligations under these regimes are highly uncertain, JEN is proposing to use a simple pass through mechanism to recover these costs.

Other new regulations have recently come into operation in relation to safety management and environmental protection. JEN is able to estimate the costs of compliance and these have been included in its cost forecasts.

Expected demand and customer growth

Given the importance of accurate demand forecasting, JEN has commissioned a highly-competent independent expert to develop forecasts.

The National Institute of Economic and Industry Research (**NIEIR**) expects that small customer electricity usage will decline by 1.6 per cent per year from 2010 to 2015. NIEIR attributes this level of growth to price and market effects of the carbon pollution reduction scheme, Commonwealth and Victorian energy policies including the AMI roll out, and the increasing use of new more efficient electricity appliances.

NIEIR also forecasts a decline in large customer usage for JEN on average by 1.6 per cent per year, mainly due to a general economic downturn, and in 2012-13 due to the introduction of emissions trading.

Jemena's experience shows how policy measures and other market trends can affect electricity load, and how necessary it is to factor them into demand forecasts. Failure to give appropriate recognition to all significant factors can result in inaccurate forecasts, effectively denying JEN an opportunity to recover at least its efficient costs.

JEN’s plans for the future

In response to JEN’s demand trends and the increasingly challenging business environment, JEN has plans to make minor amendments to the classifications of its services, maintain its current level of reliability, and move forward with a new capital program.

Services

JEN has developed its proposed service classifications and negotiating framework to best achieve the national electricity objective. JEN agrees with the AER’s proposed classifications, other than the competitive and non-competitive components of connection and augmentation services as negotiated distribution services. JEN proposes to classify all new connection and augmentation works as standard control services.

Target performance outcomes

JEN’s operating capital (**opex**) and capital expenditure (**capex**) plans outlined in this proposal are designed to maintain reliability performance at the current five year average historical level, to deliver improved customer service during major emergency events, as well as continue to foster a positive customer service business culture. JEN may also undertake additional targeted improvements over the next regulatory period where these can be justified under the AER’s service target performance incentive scheme.

Power quality is becoming an increasingly important issue for electricity customers, electrical equipment suppliers and manufacturers. The aim of JEN’s power quality plan is to maintain power quality levels within current performance levels.

Capital program

JEN plans to strike an appropriate balance between operational and maintenance expenditure, new capital works and service outcomes.

With the expected level of demand and new connections together with anticipated climate change effects, JEN can only maintain its current levels of maintenance activity and unplanned outages if it makes substantial investments in new capacity, network reinforcement and in replacing aged assets. An extensive review and analysis of JEN’s assets over the past year has taken account of JEN’s demand and customer growth, the age of its assets, and their impact on continuity of supply. JEN intends to make its investments just-in-time with efficient solutions to meet its market’s needs.

JEN also intends to implement new information systems to attain efficiency and capability standards consistent with today’s good industry practice and to meet the increasing requirements of the wholesale and retail electricity market. An extensive assessment has found that the life and usefulness of JEN's information technology infrastructure and applications are coming to an end after many years of service.

Accordingly, JEN plans to invest a total of $669.2 million in its network and information technology over the next period. Major new projects include:

- *Four new zone substations* – JEN will procure land and construct new zone substations in Broadmeadows South, Craigieburn, Alphington and Tullamarine to meet network expansion requirements arising from growth in the customer base.

- *Distribution substation augmentations* – JEN will augment over 1,000 distribution substations to ensure current performance is maintained amid growing customer demand and increasing weather severity arising from climate change.

- *Major IT projects* – JEN will undertake extensive systems investment including replacing its SAP enterprise asset management system and building a disaster recovery data centre, and establishing a geographical information system.

JEN's plans also include many smaller projects including those aimed at replacing and upgrading its ageing network and IT assets to ensure they continue to operate safely and reliably.

In addition to its mass roll-out of advanced metering infrastructure, JEN intends to pilot and trial new technologies that that can improve the intelligence and responsiveness of its network. It has plans to develop new ways to process the information this technology will provide so it can plan and respond more dynamically in the emerging market environment of real-time customer participation and more dispersed and renewable generation.

The financial capacity of JEN to undertake this vital work depends of the outcomes of its distribution determination, most significantly the cost of capital allowed.

Cost of capital

The cost of capital set in JEN's price review decision provides the main driver for efficient investment.

JEN recognises the AER's May 2009 Statement of Regulatory Intent and brings forward persuasive new evidence on the value of imputation credits and the market risk premium especially in the light of prevailing market conditions. Work presented in this proposal also demonstrates a new means of assessing the reliability of market data to enable the debt risk premium to be calculated with more confidence.

Overall proposal package

This proposal represents an average increase in network prices for JEN's customers of 1.27 cents per kWh. The substantial value that customers will receive from JEN in return is its sustained reliability, power quality and customer service, and its capacity to meet their increasing demands, in a rapidly challenging environment.

1 Introduction

The National Electricity Law (**NEL**) implemented in Victoria, pursuant to the *National Electricity (Victoria) Act 2005*, and the National Electricity Rules made pursuant to the NEL (the **Rules**) require the AER to make a distribution determination. The determination will impose controls over the prices for direct control services offered by JEN for the five years commencing 1 January 2011 (the **forthcoming regulatory control period**).

In accordance with clause 6.8.2(b) of the Rules, JEN is required to lodge a regulatory proposal with the Australian Energy Regulator (**AER**) on or before 30 November 2009. This document and its appendices and templates constitute that proposal.

This chapter sets out the scope of JEN's regulatory proposal, and how it is structured to meet the requirements of the Rules.

1.1 Scope of JEN's regulatory proposal

JEN's regulatory proposal complies with the requirements of clause 6.8.2 and S6.1 of the Rules. It sets out the funding requirements for the capital and operating investment programs that must be undertaken to ensure a safe and reliable network over the forthcoming regulatory control period.

This regulatory proposal also outlines direct control services and negotiated distribution services for use of JEN's regulated distribution system for the forthcoming regulatory control period in accordance with clause 6.2.2 of the Rules.

This regulatory proposal is submitted in accordance with, and for compliance with, the requirements of:

- the NEL
- the Rules including the Transitional Rules
- relevant AER guidelines (subject to the requirements of the Rules), including:
  - the post tax revenue model (**PTRM**)
  - the roll forward model (**RFM**)
  - the efficiency benefit sharing scheme (**EBSS**)
  - the service target performance incentive scheme (**STPIS**)

– the demand management incentive scheme (**DMIS**)

– control mechanisms for direct control services and alternative control services

– Victorian electricity distribution network service providers cost allocation guidelines issued June 2008

- the AER's Framework and Approach Paper (**F&A Paper**) issued May 2009
- the AER's Regulatory Information Notice (**RIN**) issued to JEN on 13 October 2009.

The AER has a number of discretionary calls to make in its electricity distribution price review (**EDPR**) determination, and is entitled to substitute amounts or values where it does not approve an element of a regulatory proposal to the extent necessary to enable that amount or value to be approved in accordance with the Rules. The recent decision by the Tribunal has emphasised that, in exercising its discretion, the AER needs to show in the reasons provided for its decision in accordance with clause 6.12.2 of the Rules that the decision reached is reasonable and not arbitrary. JEN therefore expects that, to the extent the AER does not agree with any aspect of JEN's proposal, the AER will provide clear and detailed explanations in its draft determination, allowing JEN to understand the AER's reasons and respond appropriately.

Explanatory notes

The indicative prices provided in this regulatory proposal (under clause 6.8.2(c)(4) of the Rules) are estimates only and do not represent JEN's initial pricing proposal or any annual pricing proposal as contemplated in the Rules. A pricing proposal will be submitted in accordance with clause 6.18.2 of the Rules after the AER publishes its distribution determination.

All monetary amounts presented in this regulatory proposal are expressed in real 2010 dollars, are in millions of dollars and apply to 1 January to 30 December regulatory years unless otherwise stated. Tables may not add due to rounding.

1.1.2 Demonstration of Rules and RIN compliance

JEN's responses to the Rules and RIN information requirements are in the main body of, and attachments to, this regulatory proposal. In compliance with RIN clause 1.1(d), Appendix 3 references each RIN response to its location within this regulatory proposal.

The AER information templates are attached in Appendix 6.

There are some areas identified in this regulatory proposal and templates where information in the exact form contemplated by the RIN is not available due to matters beyond JEN's reasonable control.

Issues arise due to:

- differing approaches adopted by the ESC and AER over time
- compliance with historic approved regulatory accounting policies
- changes in ownership of JEN and its predecessors.

These factors affect the availability and access to historical information in the various forms contemplated.

Where such instances arise, JEN has used available information to present its data in the format requested. JEN has also provided extensive details of all allocators and assumptions relevant to its RIN population. These details are set out In Appendix 6.

1.2 Claim for confidentiality

In compliance with clause 6.8.2(c)(6) the Rules, JEN claims confidentiality over certain sections of this document, attachments, appendices and pro formas as identified in Table 1-2. JEN has marked the relevant sections in underlined text. JEN requests that the AER not disclose the information contained in these sections, attachments, appendices and pro formas to any person outside the AER.

1.3 Structure of document

The remainder of this regulatory proposal is structured as set out in Table 1-1.

Table 1-1: Regulatory proposal structure

Chapter	Title	Purpose
2	Business overview and context	Chapter 2 provides an overview of the key characteristics of JEN's business and the environment that affects the development of this regulatory proposal
3	Regulatory obligations or requirements	Chapter 3 summarises the regulatory and service standard obligations that materially affect JEN's forecast capital and operating expenditures. It specifically addresses the service performance and reliability obligations related to JEN's provision of direct control services
4	Classification of services and	Chapter 4 provides an overview of the AER's proposed classification of services in its F&A Paper,

Chapter	Title	Purpose
	negotiating framework	JEN's response to the AER's proposed classification of services and its rationale for proposing different classifications
5	Current performance	Chapter 5 describes JEN's cost and service performance during the current regulatory control period. It discusses JEN's actual and projected results compared with the ESC allowances and over the current regulatory control period. It provides an explanation for significant variations between actual and forecast results for demand and customer numbers, capital and operating expenditure and network performance and utilisation
6	Demand and customer number forecasts	Chapter 6 details the basis of JEN's approach to developing its demand and customer number forecasts and provides forecasts for customer numbers, peak demand and energy over the forthcoming regulatory control period
7	Target performance outcomes	Chapter 7 describes JEN's approach to network planning and management and sets out its target performance outcomes for the forthcoming regulatory control period as background to the expenditure forecasts in Chapters 8 and 9
8	Forecast capital expenditure	Chapter 8 provides JEN's forecast capex and explains how this regulatory proposal complies with the capital expenditure objectives, criteria and factors specified in the Rules. It also sets out the key assumptions that support JEN's forecast capital expenditure for the forthcoming regulatory control period
9	Forecast operating expenditure	Chapter 9 provides JEN's forecast opex and explains how this regulatory proposal complies with the operating expenditure objectives, criteria and factors specified in the Rules. It also sets out the key assumptions that support JEN's forecast operating expenditure for the forthcoming regulatory control period
10	Regulatory asset base	Chapter 10 sets out the method used to roll forward JEN's Regulatory Asset Base (RAB), its forecast capital contributions and disposals, and a summary of the resultant RAB outcomes over the forthcoming regulatory control period
11	Depreciation	Chapter 11 sets out the method JEN has used to calculate its depreciation allowance in the building block revenue proposal for the forthcoming regulatory control period. It also sets out the standard and remaining lives of JEN's network system and non-

Chapter	Title	Purpose
		system assets
12	Return on capital, inflation and taxation	Chapter 12 sets out how JEN has calculated its proposed return on capital, its estimated cost of corporate tax and its proposed method that is likely to result in the best estimates of inflation used in the derivation of the building block revenue for the forthcoming regulatory control period
13	Revenue requirements and indicative pricing for standard control services	Chapter 13 sets out an overview of the completed PRTM and JEN's total revenue requirements. It includes the building block components of JEN's proposed revenue requirements over the forthcoming regulatory control period, the resulting X factors to achieve JEN's revenue requirements, and indicative prices for its direct control services
14	Price control mechanism	Chapter 14 provides JEN's response to the AER on its proposed price control mechanism and includes JEN's proposals for further controls to its standard control services
15	Pass through events	Chapter 15 provides details of JEN's nominated cost pass through events and associated materiality thresholds
16	Service target performance incentive scheme	Chapter 16 sets out JEN's response and relevant considerations relating to the AER's F&A Paper and published guideline on the service target performance incentive scheme
17	Efficiency benefit sharing scheme	Chapter 17 sets out JEN's response and relevant considerations relating to the AER's F&A Paper and published guideline on the efficiency benefit sharing scheme
18	Transitional matters	Chapter 18 provides details of the transitional matters arising from the move to a national regulatory framework
19	Alternative control services	Chapter 19 sets out JEN's regulatory proposal for its alternative control services. It provides details of the control mechanism proposed for each service, indicative prices over the forthcoming regulatory control period and how JEN arrived that those indicative prices.

JEN's appendices, pro formas and models submitted to support its regulatory proposal are set out in Table 1-2.

Table 1-2: Appendices

Appendix	Title	Purpose	Confidentiality
	Glossary		
A1	Statutory declaration	RIN compliance	Public
A2	Certification of reasonableness of key assumptions	RIN and Rule compliance	Public
A3.1	Compliance of JEN's proposal to Schedule 1 on RIN	RIN compliance	Public
A3.2	Capital Expenditure - RIN 3.1 - 3.9 compliance summary	RIN compliance	Public
A3.3	Operating Expenditure - RIN clause 4.2 compliance summary	RIN compliance	Public
A3.4	Demand and Customer Number Forecasts – RIN clause 11 compliance summary	RIN compliance	Public
A4	AER RFM	Model for Rule compliance	Confidential
A5	AER PTRM	Model for Rule compliance	Confidential
A6	Explanatory notes to RIN templates	RIN compliance	Confidential
A6A	AER RIN templates for JEN service classification	RIN compliance	Confidential
A6B	AER RIN templates for AER service classification	RIN compliance	Confidential
A7.1	SKM - Annual Material Cost Escalators 2010-15	SKM report - expert report that JEN has relied upon in preparing this proposal	Public
A7.2	Wages Outlook for the Electricity Distribution Sector in Victoria	BIS Shrapnel report - Expert report that JEN has relied upon in preparing this proposal	Public
A7.3	Independent Review of Whole of Business Cost Allocation	PwC report - Expert report that JEN has relied upon in preparing this proposal	Confidential
A7.4	Electrical sales and customer number forecasts to 2019 for the JEN	NIEIR report - Expert report that JEN has relied upon in	Public

Appendix	Title	Purpose	Confidentiality
	electricity region	preparing this proposal	
A7.5	Peak demand forecasts	NIEIR report - Expert report that JEN has relied upon in preparing this proposal	Public
A7.6	Independent Review Conclusions on IT Capital Expenditure	E&Y review - Expert report that JEN has relied upon in preparing this proposal	Public version
A7.7	Independent review of JEN's capital expenditure forecasts	GDH review - Expert report that JEN has relied upon in preparing this proposal	Public version
A7.8	Assessment of Climate Change Impacts on Jemena Electricity Networks for 2011-15 EDPR	AECOM report - Expert report that JEN has relied upon in preparing this proposal	Public
A7.9	Self Insurance Risk Quantification Final Report	Marsh report - Expert report that JEN has relied upon in preparing this proposal	Confidential
A7.10	Weighted average cost of capital Supporting Documents	Expert reports that JEN has relied upon in preparing this proposal	Public
A7.11	Verification of Demand Data Used in Regulatory Models	Deloitte report - Expert report that JEN has relied upon in preparing this proposal	Confidential
A7.12	Asset Management Agreement Margin	Evans and Peck report - Expert report that JEN has relied upon in preparing this proposal	Confidential
A7.13	ACG review of NERA's benchmarking of contractors' margins critique	NERA report – Expert report that JEN has relied upon in preparing this proposal	Public
A8	Jemena Electricity Networks (Vic) Ltd - Cost allocation methodology	Rule compliance	Public
A9.1	Jemena Electricity Networks (Vic) Ltd Network Asset Management Plan (NAMP) 2010-15	Basis of JEN's network capital expenditure forecasts	Confidential
A9.2	JEN IT Strategy Asset Management Plan 2011	Basis of JEN's IT capital and operating expenditure	Confidential

Appendix	Title	Purpose	Confidentiality
		forecasts	
A9.3	JEN activity prices	RIN compliance	Confidential
A9.4	Strategic objectives	RIN compliance	Confidential
A10	Capital and operating work plan	Basis of JEN's capital and operating expenditure forecasts	Confidential
A11	Policies, strategies and procedures	RIN compliance	Confidential
A12	Self insurance policy – board paper and directors circular resolution	RIN compliance	Confidential
A13	Forecast data models	Model detailing basis of operating expenditure forecasts	Confidential
A14	Jemena Electricity Networks (Vic) Ltd's Historical Background	Contextual information on JEN	Public
A15	Current enterprise bargaining agreements	RIN compliance	Confidential
A16	Supporting information for alternative control services and customer connections	RIN compliance	Confidential
A17.1 to A17.20	Related party documentation	RIN compliance	Confidential
A18	Regulatory obligations and requirements	RIN compliance	Public
A19	Negotiating framework	Rule compliance	Public

2 Business overview and context

This chapter describes some features that affect the way JEN operates its business, and JEN's planning, operation and development of the network. Chapter 7 then describes JEN's network strategy to address these challenges. The underlying characteristics of JEN's business and the external environment affect the projected demand for JEN's services and the forecast costs of providing these services.

This chapter is structured as follows:

- *Summary* - provides an overview of JEN's business and the external environment it operates in
- *Creation and ownership of JEN* – describes JEN's ownership history and the implications for availability of information
- *Previous regulatory decisions* – sets out features of the three decisions made by independent regulators for JEN's economic regulation
- *JEN's network area* – provides an overview of the key characteristics of the area serviced by JEN
- *Customers and demand profile* – describes JEN's customers and the resulting demand profile within its network area
- *System and network assets* – provides an overview of JEN's system and network assets
- *Delivery of JEN's services* – describes how JEN delivers its services through a mixture of in-house functions and outsourced activities
- *External factors affecting JEN's operations* – provides an overview of the key external factors that affect JEN's operations and costs

2.1 Summary

The key messages of this chapter are:

- JEN's distribution network covers approximately 950 square kilometres of the north western area of greater Melbourne. The area includes the city's international airport, major transport routes and areas of residential and industrial growth. With approximately 305,000 customers (2010 average), it is the smallest of the five electricity distribution businesses in Victoria.

- As the smallest of five Victorian networks, some of JEN's fixed costs do not benefit from the same scale economies as other networks. Its size increases its sensitivity to market changes and makes it more reliant on outsourcing to larger scale asset service providers to capture scale benefits inherent in larger networks. Accordingly, JEN has outsourced many of its activities, including through JAM, which provides comparable services to other utilities. This regulatory proposal assumes that current outsourcing arrangements and associated cost benefits will continue over the forthcoming regulatory control period.

- JEN's area includes a number of older suburbs with aging infrastructure. Asset deterioration is accelerating due to climate change and extreme weather events.

- Since initial privatisation, JEN's predecessor entities have been the subject of continuing mergers and acquisitions. JEN's network assets have been constructed and managed over many years by JEN's predecessors to different standards and using different systems. This complexity increases the costs of prudent asset management and planning, especially as many of these network assets are reaching their end-of-life replacement. It also affects JEN's ability to access consistent historical data.

2.2 The creation and ownership of JEN

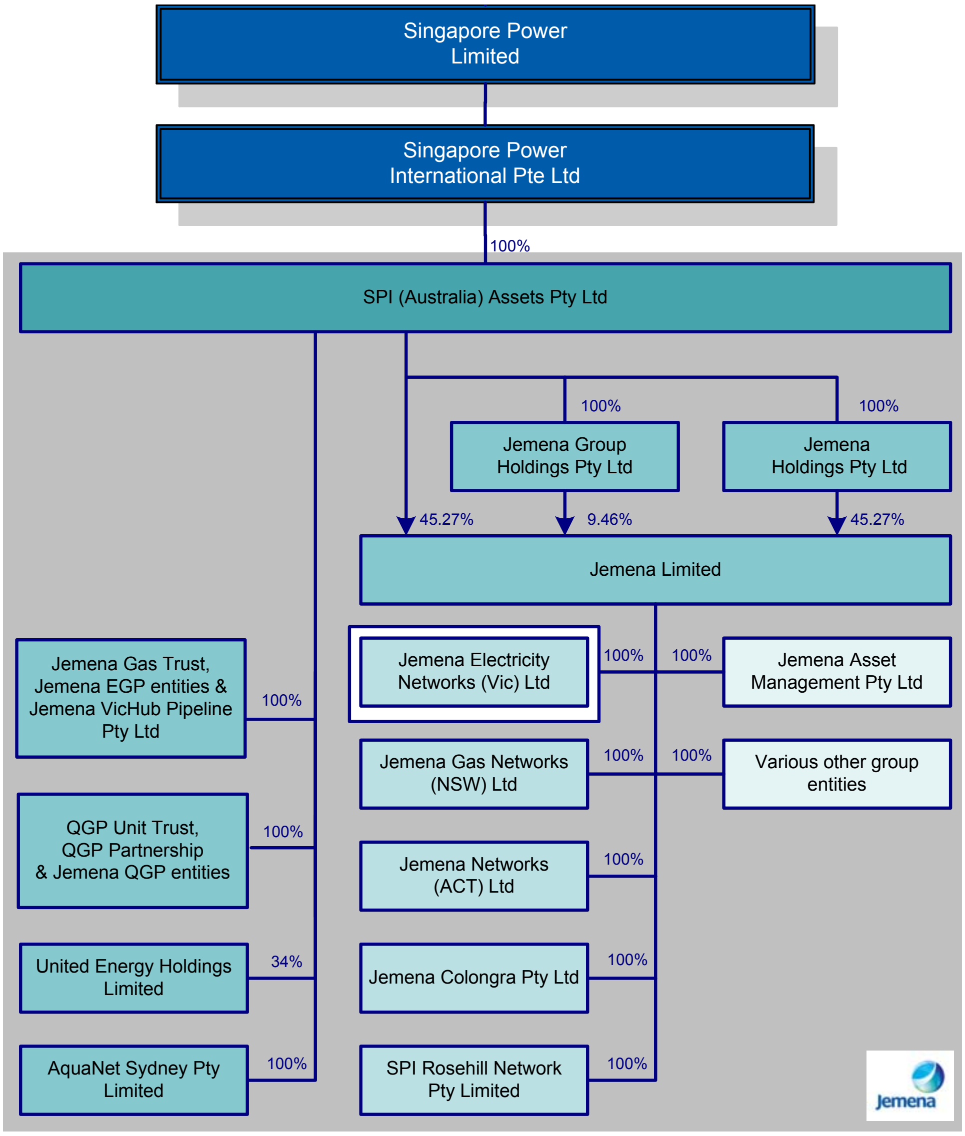
2.2.1 Ownership history

Appendix 14 describes the changes that have occurred in the ownership and administration of what is now known as Jemena Electricity Networks (Vic) Ltd commencing with its formation at privatisation.

Within the current regulatory control period a change in ownership of JEN occurred in October 2006, with Alinta Limited's acquisition of the Australian Gas Light Company (**AGL**), including AGL Electricity Limited (**AGLE**). That company was then renamed Alinta AE Ltd. Ownership changed again on 31 August 2007, when Singapore Power International acquired a portion of Alinta's assets, including 100 per cent of the shares in Alinta AE Ltd. The company was subsequently renamed Jemena Electricity Networks (Vic) Ltd (**JEN**).

Figure 2-1 is a schematic diagram showing relevant elements of the group corporate structure in which JEN now resides.

Figure 2-1: Jemena group corporate structure



SPI (Australia) Assets Pty Limited is the principal Australian holding company for the Jemena Group, which owns a 100 per cent interest in JEN. The Jemena Group also includes full ownership interests in:

- the Queensland Gas Pipeline (**QGP**), Eastern Gas Pipeline (**EGP**) and VicHub gas transmission pipelines
- the NSW gas distribution network owned by Jemena Gas Networks (NSW) Ltd
- AquaNet, a recycled water network development project and recycled water retailing business in NSW (the network assets being owned by SPI Rosehill

Network Pty Limited and the water business being owned by AquaNet Sydney Pty Limited)

- the Colongra lateral and gas storage pipeline, owned by Jemena Colongra Pty Limited
- an infrastructure and asset management business called Jemena Asset Management, which is made up of Jemena Asset Management Pty Limited and a number of associated entities.

The Jemena Group also holds a 50 per cent partnership interest in ActewAGL Distribution. ActewAGL Distribution owns gas and electricity distribution networks in the ACT. The Jemena Group has a 34 per cent interest in United Energy Distribution.

2.2.2 Implications for information availability

JEN's history is one of continual ownership change, with the result that there has been a succession of different corporate objectives, policies and reporting procedures applied to JEN by its owners. The changes of ownership have resulted in significant discontinuities in information availability and systems within the business. A key consequence of this is the inability for JEN to access disaggregated cost information of the nature contemplated in certain aspects of the RIN.

While JEN's historic regulatory accounts and other high-level information is available for the full 2001-2008 period, much of the detailed information prior to October 2006 upon which this material was based either is no longer in JEN's possession, or can no longer be verified. This is because prior to this time, JEN's assets were part of a vertically integrated electricity business owned by AGL. In October 2006, AGL sold those assets to Alinta. The transaction required a split in management and financial systems, with AGL retaining the bulk of the original systems, and Alinta setting up new systems and migrating historic information that was considered relevant across to Alinta systems. The transition in ownership and systems took place over the end of 2006 and beginning of 2007.

Over time, it has become apparent that much of the relevant detailed information was not migrated, and some of the migrated historic information contains errors created in the migration process and only identified at a later stage.

2.3 Previous regulatory decisions

JEN's network has been subject to independent economic regulation by the ESC since 2000. Key components of JEN's revenue and pricing have been the subject of several major regulatory investigations by the ESC and of public consultation.

The ESC has made a number of key past decisions which have flowed through to subsequent regulatory periods, including:

2.3.1 Setting regulatory asset base and initial incentive schemes

In its 2000 determination, the ESC affirmed JEN's regulatory asset base (**RAB**) set during the privatisation process.

The ESC introduced operating expenditure (**opex**) and capital expenditure (**capex**) efficiency carryover incentives to improve JEN's operational and capital efficiency. It was allowed to retain approximately 30 per cent of any efficiency gains, while around 70 per cent was to be passed on to customers.

The ESC also introduced an S-factor reliability incentive scheme with exclusion mechanisms for abnormal events and those interruptions that were beyond the control of the distributor. Distributors became liable for guaranteed service level (**GSL**) payments for customers experiencing poor service reliability and encourage improve the timeliness of supply connections, repair of street lights faults, and keeping appointments.

JEN's new public lighting (installed after 31 December 2000) was separated into its own asset base.

The 2000 EDPR resulted in a real reduction in JEN distribution charges of 17.1 per cent in 2001 and 1 per cent per year thereafter until 2005.

2.3.2 Refining the incentives

In 2005, the ESC rolled forward JEN's capital base incorporating JEN's actual capital expenditure.

While recognising the effectiveness of its initial performance incentive scheme, and the improving level of reliability that JEN's network was achieving, the ESC refined this scheme by expanding the S-factor to include call centre performance and by increasing GSL payments in some areas. Additionally, the EDPR expanded the GSL payments to include payments for momentary interruptions above a set threshold.

While the ESC allowed the impact of certain events to be excluded from the calculation of the S-factor and from the requirement to make certain GSL payments it noted that the qualitative exclusions were somewhat broad and that there remained a level of subjectivity in their application. Consequently, the ESC set the quantitative exclusion criterion sufficiently high to limit the supply interruptions events to those that were abnormal. This recognised that the existing scheme was administratively complex and costly for distributors and the ESC.

The 2006 EDPR removed the capex efficiency carryover component of the benefit sharing scheme.

In a first step towards establishing a mandate for smart metering, the ESC separated new metering into its own RAB and established an allowance for the interval metering roll-out (**IMRO**). This was intended to provide a platform for the delivery of improved demand management outcomes and greater efficiency in distribution services and related markets.

The 2006 EDPR resulted in a real price reduction for JEN of 3.1 per cent in 2006, with a further 1.2 per cent reduction per annum over the following four years. This small price reduction was an indication that JEN had little scope to substantially increase its operational efficiency under its then asset management services arrangement, and that its capital program reflected that most of its assets were not yet approaching the end of their useful lives.

2.3.3 Establishing advanced metering infrastructure

In October 2009, the AER released its first Final Determination for JEN's budget and charges applications made in accordance with an Order in Council (**OIC**) under section 15A(2) and section 46D of the Electricity Industry Act 2000. The purpose of the OIC is to establish JEN's metering charges and enable it to recover its actual costs for activities within the scope set out in the order for the provision of AMI services.

JEN has commenced an appeal in the Australian Competition Tribunal from the AER's Final Determination.

In the two months to the end of November 2009, JEN has rolled out around 8,500 AMI meters to residential customers and is on track to meet its licence obligation to roll out 5 per cent by 30 June 2010.

2.4 JEN's network area

JEN supplies electricity to over 305,000 customers (average for 2010) of which about 91 per cent are residential. These customers cover a 950 km^2 area of Melbourne's city and north-western suburbs, with Tullamarine International Airport at the approximate centre.

The network service area ranges from Couangalt, Clarkefield and Mickleham in the north to Williamstown and Footscray in the south and from Hillside, Sydenham and Brooklyn in the west to Yallambie and Heidelberg in the east. JEN's network varies across its area in terms of asset type and age, and the demographics of its customers.

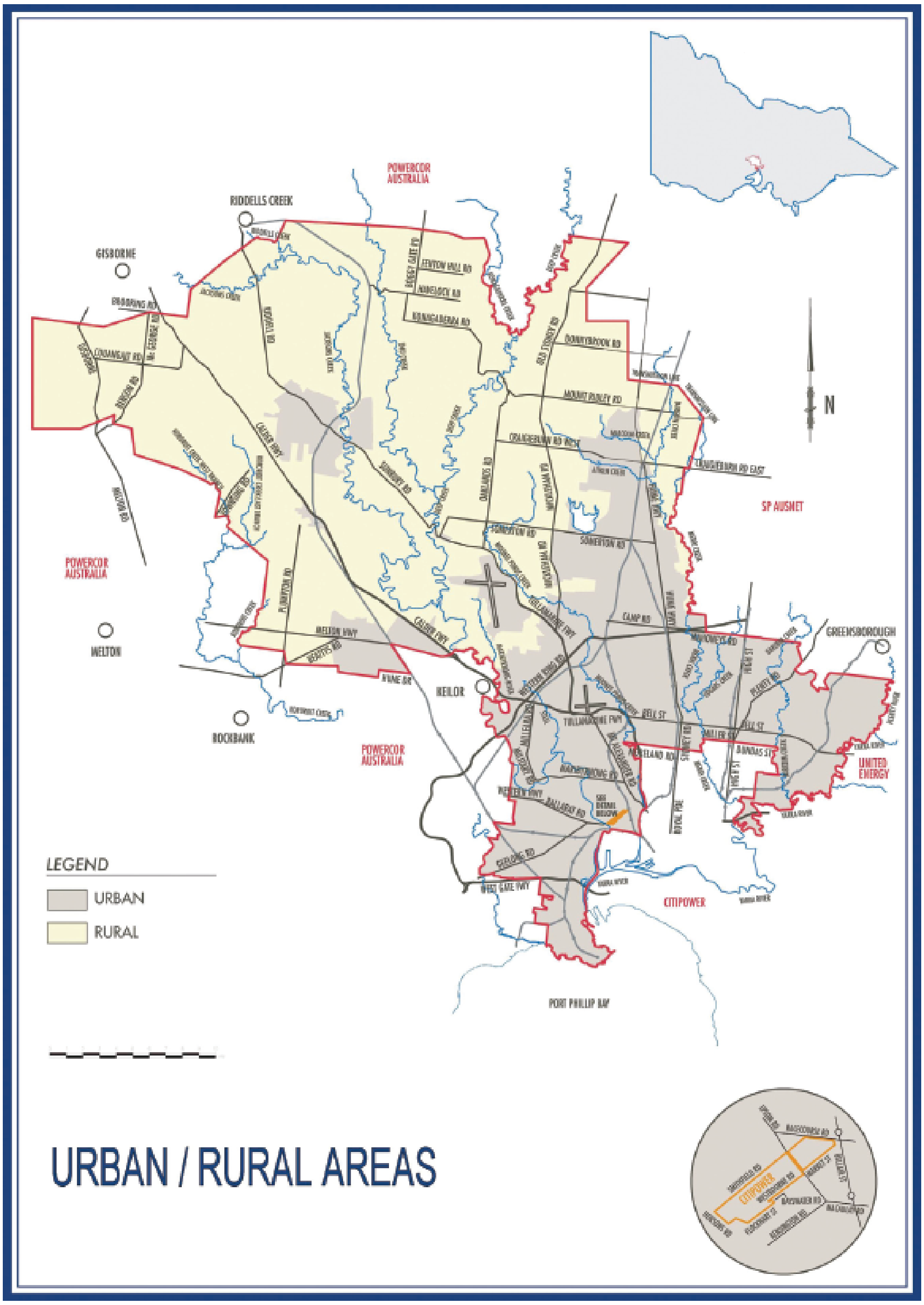
JEN’s network supplies electricity to a large proportion of the northern and western suburbs of Melbourne. Many of these suburbs are old with network components of variable standards acquired from various sources, and nearing the end of their life.

The network footprint incorporates a mix of major industrial areas, residential growth areas, established inner suburbs, Melbourne International Airport and some major transport routes.

The network primarily serves an inner urban area as illustrated in Figure 2-2. This area is undergoing significant change and development, which brings changing community attitudes and lifestyles. Councils representing their changing constituents are taking increasing interest in the form and maintenance of the network. This affects network activities, requiring additional consultation in areas such as the location of new assets.

JEN supplies 12 per cent of Victorian customers and is the smallest of the five distributors in Victoria. It distributes approximately 75 per cent of the energy of the next smallest distributor (Citipower) and less than half that of the largest Victorian distributor (Powercor).

Figure 2-2: JEN network characteristics



2.5 Customers and demand profile

2.5.1 Economic structure

The network delivers in excess of 4,373 GWh of energy to about 305,000 electricity sites. The main features of the JEN distribution region are:

- it accounts for around 12 per cent of Victoria's population and around 11 per cent of residential housing in Victoria

- the manufacturing sector is relatively large, representing nearly 13 per cent of the state total, compared with the total gross output of the JEN region representing only 8.3 per cent of the Victorian total.

Concentrations of manufacturing industries in the JEN region are textiles, clothing and footwear, transport equipment and chemicals. The region has a relatively small share of finance, property and business services; and recreation and other services. The dominant tertiary sector industry is transport and storage, partly reflecting road transport services along the Hume Highway, as well as air transport services surrounding Melbourne’s airports.

2.5.2 Population and gross regional product

Forecasts for population growth and gross regional product vary across JEN’s region, affecting the timing and location of expenditure. JEN is expected to continue to have the smallest number of customers during the forthcoming regulatory control period. This makes JEN relatively more susceptible to cost changes because it has a small customer base to recover these from and necessitates innovative operational structuring and service delivery to achieve efficient costs.

2.6 System and network assets

JEN’s forecast capex and opex investment is designed to enable JEN’s network and IT to deliver an appropriate level of customer service in compliance with its regulatory obligations. These take account of the impact of aging infrastructure and the asset integrity issues highlighted below on asset replacement requirements as well as the increasing utilisation of network assets.

Despite its comparatively small size, JEN’s network includes a wide range of assets. It includes around 6,000 km of power line (excluding customer’s services) on 91,300 high and low voltage poles. Additionally around 21 per cent of the urban network and 34 per cent of the rural network is underground.

Terminal stations are the connection points for JEN’s electricity network to the extra-high voltage transmission grid. SP AusNet’s terminal stations have power transformers that typically reduce the 500 kV or 220 kV transmission voltage to 66 kV. The stations provide JEN with bulk electricity at the subtransmission voltages (66 kV or 22 kV). There are six terminal stations that supply JEN, being Brunswick, Brooklyn, Keilor, Templestowe, Thomastown and West Melbourne terminal stations.

Figure 2-3 illustrates JEN's network and station configuration.

Figure 2-3: JEN network area and station configuration

Subtransmission network

The JEN subtransmission network consists of 41 lines operating at 66 kV or 22 kV (predominantly 66 kV) that transmit bulk electricity from terminal stations to zone substations located throughout the distribution area. It is predominantly of overhead construction, but comprises both overhead and underground cable systems. Overhead lines are supported by wood or concrete poles, apart from twenty-five steel tower constructions. The majority of concrete poles have steel cross-arms with post type insulators; whilst wood poles have either wood or steel cross-arms and either pin or post type insulators.

The subtransmission network is constructed in the form of a series of closed loop dedicated feeders that interconnect zone substations with primary grid supply terminal stations. A single subtransmission feeder outage will not generally result in loss of supply to customers unless the feeder outage occurs during peak demand time and the loop is loaded above its rating under probabilistic planning. Transformers at Fairfield and North Essendon zone substations are supplied by means of three radial 22 kV subtransmission feeders.

Commonly, support structures for subtransmission and high voltage lines carry subsidiary circuits at more than one voltage level as this design results in saving in construction costs as well as the required right-of-way. The network includes both high and low voltage poles.

Zone substations

JEN has a total of 23 owned zone substations and one subtransmission switching station located at the Somerton Power Station. In addition, there are a number of customer owned zone substations that are supplied via the network and a number of other distribution business-owned zone substations from which electrical energy is distributed.

By 2016, 23 transformers located at various zone substations will be in excess of 50 years of age. The oldest of the transformers on the network dates from 1925. Over the next 5 to 10 years, many transformers operating on the network will reach an age where assessments and decisions on age related retirement will need to be made. These decisions will be based on condition assessments and are designed to balance the risk of failure against the deferral of capital expenditure.

Large numbers of circuit breakers have been in service beyond their expected life; this situation will need to be managed over the next 10 years.

The utilisation at zone substations has been steadily increasing since 2002 with current utilisation being 13 per cent higher than in 2002. This indicates that spare network capacity has been used up to meet growing demand. However, this cannot continue at the same rate into the future without affecting the security of supply to customers.

High voltage network

JEN's high voltage network consists of 212 high voltage feeders operating at 22, 11 or 6.6 kV that distribute electricity from zone substations to local distribution substations through an interconnected network of overhead and underground cable systems.

The high voltage distribution network operates mainly at 22 kV but with substantial 11 kV and a lesser amount of 6.6 kV distribution. The network configuration consists of a series of highly interconnected radial feeders in the form of open rings to supply distribution substations that provide voltage transformation for local reticulation at low voltage.

Though predominantly of overhead construction, the distribution network is comprised of both overhead and underground cable systems and substations. The network includes all of the poles, wires, cables and associated switchgear, fuses and substations together with property services, cables, pits, pillars and associated hardware that facilitate the distribution of electrical energy.

Most new development of the network utilises underground technologies where it results in the lowest lifecycle costs.

The utilisation at high-voltage feeders has been steadily increasing since 2002 with current utilisation being 7 per cent higher than in 2002. This indicates that spare network capacity has been used up to meet growing demand. However, this cannot continue at the same rate into the future without affecting the security of supply to customers.

Distribution substations

JEN has 5260 distribution substations which convert the distribution high voltage to low voltage for use by the majority of network customers. A distribution substation can be an indoor substation (located within a building), a kiosk substation, a ground substation or a pole substation. These can be supplied at 22, 11 or 6.6 kV. In many situations, a customer will own the building that houses electrical equipment.

Low voltage network

The low voltage network delivers electrical energy at 400/230 volts from local distribution substations into customers' premises. Low voltage lines are relatively short (typical upper limit of approximately 500 metres) because of voltage drop and consequently supply quality limitations. The majority of low voltage lines are of overhead construction. However current government policy is to place low voltage lines in new residential housing estates underground to comply with urban planning guidelines.

JEN's low voltage network consists of radial circuits supplied by distribution substations, with multiple interconnections at open points between adjacent substations in urban areas.

Service connections – low voltage

Customers' service connections are a major component of network assets. The majority of connections are overhead (180,000 of the 230,000 low voltage connections), with the remainder connected to the underground low voltage network.

Individually, these are low cost assets but the numbers involved mean that as an asset type, they represent a significant investment. The service connection is the point at which a network customer's installation interacts with the network. Consequently, a range of safety and regulatory issues must be managed at that interface.

Meters

JEN operates approximately 300,000 energy meters for customers with annual consumption of less than 160 MWh. Each meter is a relatively low cost item but as an asset class, meters represent a significant investment.

Each customer installation has at least one meter installation to record the consumption of electrical energy. This data is gathered by either accumulation type meters or by time of use or interval meters. Interval meters record usage in 15-minute intervals. This data can be used to determine hourly usage, whilst measuring and recording maximum demand. Metering assets include direct connected meters, instrument transformer connected meters and the associated current and voltage instrument transformers.

As described in section 2.3.3 of this proposal, the costs related to metering services are primarily recovered under a separate Victorian cost recovery framework and, accordingly, funds required for the recovery of these costs are not included in JEN's regulatory proposal.

The exceptions to the metering recovery arrangement described above relate to unmetered connections, meters for customers that consume in excess of 160 MWh per year and the metering assets installed prior to 2006. These metering costs are recovered as follows:

- the costs associated with unmetered connections are recovered through alternative control charges

- the costs associated with metering assets for customers with consumption less than 160 MWh per year that were installed before 1 January 2006 are included in JEN's regulatory asset base (**RAB**) and recovered through standard control network charges

- metering services to customers with consumption greater than 160 MWh per year are not classified under the Rules and the costs associated with them are recovered through unregulated charges.

Communications

The groups of assets that comprise the JEN communications infrastructure include overhead and underground copper supervisory cable systems, a microwave link, fibre-optic cables and associated hardware and software. This system facilitates the remote control and monitoring of the electricity network, the operation of complex network protection systems and some corporate data communications.

Land and property

The group of assets that comprise the JEN land and property portfolio is a mixture of freehold and leasehold properties. The portfolio is made up of land on which owned and leased distribution substations are located, easements or memoranda of agreements, owned and leased zone substation sites, and an owned major works depot.

Asset management business systems

JEN owns core asset management business systems, which comprise:

- a geographical information system (**GIS**)

- a SAP works management and logistics system

- supervisory control and data acquisition (**SCADA**), a distribution management system (**DMS**)

- a customer information system (**CIS+**)

- a substation utilisation and profiling system

- an engineering drawing management system

- an electronic content management system

- field computing devices.

2.7 Delivery of JEN's services

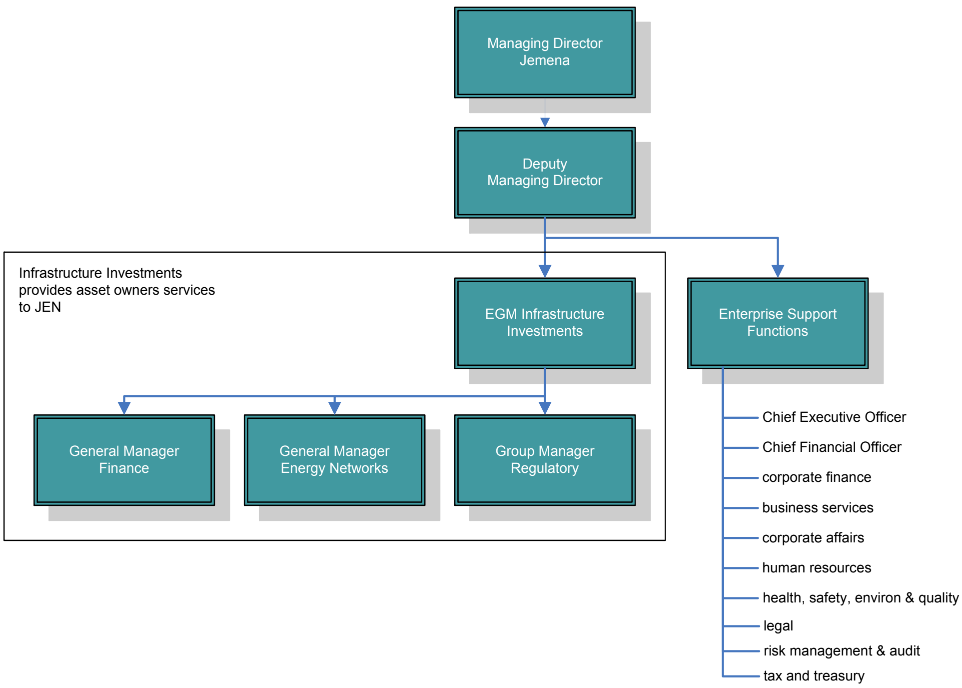
2.7.1 Structure of JEN management

As indicated in section 2.2, Jemena Limited owns 100 per cent of JEN. Jemena Limited is part of the group owned by SPIAA, which is not publicly listed on the Australian Stock Exchange.

Within Jemena Limited, the Infrastructure Investments division manages JEN's business. In addition, Jemena Limited's corporate divisions provide enterprise support functions (**ESFs**) to support the management of JEN's business.

Figure 2-4 shows the management structure of JEN.

Figure 2-4: JEN management structure



Through this structure, the Infrastructure Investments division manages an extensive range of business activities, the scope of which is summarised in Table 2-1. Their objective is to optimise JEN's commercial position and enable it to respond effectively to its market drivers and regulatory incentives.

Table 2-1: Scope of management activities

Activity	Description
Business planning and governance	• developing strategic asset plans • developing business plans and budgets • overseeing JEN's financial, commercial and technical activities
Financial management	• establishing accounting policy and procedures • reporting and forecasting financial, commercial and technical performance of the network businesses • validating cost reporting and payments • maintaining JEN's accounts
Regulatory management	• managing issues and relationships with government, regulators and market operators • managing regulatory reviews • ensuring compliance
Capital management	• identifying the scope of capital works (both growth and maintenance) required to meet JEN's growth and system performance objectives • developing arrangements to source these works at least cost • ensuring all network future capex passes regulatory tests of effectiveness and efficiency where relevant
Commercial management	• establishing commercial policies, procedures and controls • managing relationships and negotiations with retailers and major end consumers and other industry participants • ensuring performance of JEN's contractual and market obligations • ensuring the integrity of IT systems and business processes used in metering and billing of network services
Technical management	• establishing network asset performance objectives and targets • establishing frameworks and policies for management of technical risk • approving asset management plans • establishing and managing contracts for the delivery of asset management, O&M and construction services • monitoring the performance of service providers in delivery of services

Activity	Description
Enterprise support functions	• CEO – executive oversight and board liaison • CFO – executive oversight • corporate finance • business services • corporate affairs • human resources • health, safety, environment and quality • legal • risk management & audit • tax and treasury

Commercial in Confidence

2.8 External factors affecting JEN's operations

There are three key external factors that are affecting, or about to affect, JEN's operations and associated costs, and that JEN has taken into account when preparing its regulatory proposal:

- *climate change* – Increasingly, extreme weather events are having an impact on JEN's network and its reliability
- *Government policy measures in response to climate change* – The Australian Government has a stated intention to implement carbon pricing and trading, fugitive emissions reporting, and other new policies—such as renewable energy target and national hot water schemes
- *other energy market developments and regulation* – Several new developments will come into effect after the submission date for JEN's regulatory proposal including the national energy customer framework.

2.8.1 Climate change

Climate change has emerged as an issue of key focus worldwide. It is now a mainstream concern for government and industry in Australia, and our national response will represent a major shift for the energy supply industry. JEN understands the importance of minimising the risk to its assets and customers due to the effects of climate change, and the importance of contributing to solutions through strategic objectives.

A 2007 report – "Victorian Government's infrastructure and climate change risk assessment for Victoria", highlights several issues for the power industry, including increases in damage to infrastructure and maintenance costs, and increased frequency and length of power blackouts and disruption of services.[1] The report also highlights potential liability issues arising from climate change impacts for asset owners and operators[2].

Recent climatic events experienced in Victoria such as extreme heat-waves, unprecedented drought, stronger storms and more intense bushfires, further

[1] Department of Sustainability and Environment (Vic), *Victorian Government's Infrastructure and Climate Change Risk Assessment for Victoria*, 2007, p. 2.

[2] Ibid., p. 42.

substantiate the reality of climate change and the need for network businesses to manage and adapt their networks to these changing conditions.

JEN commissioned an independent report prepared by AECOM[3] that highlights the operational and cost impacts of climate change on JEN's business and network. It notes significant impacts on:

- supply restoration and reliability
- asset deterioration
- asset design requirements
- bushfire management
- insurance.

These impacts and measures aimed at addressing them are described in Chapter 7 of this regulatory proposal.

In the past 18 months, the network has been subjected to three major environment-driven events[4]. There has been significant scrutiny of the electricity industry, and inquiries into the performance of utility businesses during past storm events.

The Esplin Report, August 2008

A review of the April 2008 windstorm by the Emergency Services Commissioner recommended that:

- the electricity distribution businesses enhance power outage information on their websites which are accessible to electricity retail businesses, the media and the public and also consider improving their capacity to communicate with customers
- all Victorians should know where and how to access emergency information and advice
- the Victoria State Emergency Service work with the electricity distribution businesses, Department of Primary Industries and Energy Safe Victoria to develop and implement a joint community education program for public safety during and after storms and power outages.

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3 AECOM, *Assessment of Climate Change Impacts on Jemena Electricity Networks for 2011-2015 EDPR*, September 2009.

4 Windstorm on 2 April 2008; Heatwaves on 13- 7 Feb 2009 and 26- 27 April 2009.

Reviews of electricity distributors' communications in extreme supply events

The ESC considered a number of regulatory matters relevant to significant energy supply events so that the community can be assured that:

- the communication of supply outage details are coordinated for customers and the media
- support agencies are able to assist customers with special needs in the event that these customers are off supply for more than 24 hours
- there are improvements in regard to outage notifications to customers and options for better handling faults reported by customers
- call centres perform to high standards during these events.

The Victorian Minister for Energy and Resources has also requested that the ESC consider and progress a number of regulatory matters that are relevant to significant energy supply events. [5]

In accordance with the Minister's request, in September 2009 the ESC sought the views of the distributors and other interested parties on whether, and how, these actions can be supported by regulation or other mechanisms to provide certainty in the likelihood that these extreme supply events will continue. The ESC raised a number of possible initiatives that the distributors could undertake to help minimise the impact of significant energy supply events on customers.

JEN has included in its regulatory proposal initiatives to improve call centre performance and the enhancement of SMS and internet facilities.

2.8.2 Policies that influence generation and end use

Several government policies aimed at combating climate change are affecting the source of, and demand for electricity that JEN distributes. Three of the most significant are the roll out of advanced metering infrastructure, the renewable energy target scheme and the national hot water strategic framework.

Advanced metering infrastructure

To meet the Victorian government's mandate for advanced metering infrastructure, JEN is rolling out remotely read interval meters to 320,000[6] end-use customers over a four-year period, while maintaining existing operations.

[5] ESC, *Issues Paper: Electricity Distributors' Communications in Extreme Supply Events*, September 2009, p. 1.

[6] Number of AMI meters required by the conclusion of the AMI roll out in 2013.

The near term benefits of AMI will include reductions in the costs of providing re-energisation, de-energisation and special meter read services, as these services will in some cases be provided remotely rather than locally. These savings will accumulate as the AMI systems become fully operational, and will apply to those connections where an AMI meter is installed and is remotely read. In the case of re-energisation, the realisation of benefits is dependent on approval of new operating modes by Energy Safe Victoria. JEN has proposed indicative charges for remotely provided alternative control services.

JEN's AMI program also has the potential to enhance its distribution network infrastructure, full retail contestability, participant transactions and market systems, IT business systems and infrastructure, operational processes and controls, and organisational roles and responsibilities.

JEN is currently assessing its options to improve the planning, operation and efficiency of its network made possible by AMI, and has included associated trial costs in this proposal. In the longer term, AMI will form part of JEN's smart grid strategy that will enable JEN to manage outages better, improve customer service, and may allow the network to adapt more quickly to support new demand patterns and new sources of generation. The costs and benefits of JEN's options need to be carefully considered to determine the nature and timing of the best solutions. While JEN's work in this area is on-going, it is likely that the benefits of JEN's smart grid strategy will not be realised until the 2016-2020 regulatory period, by which time the full roll out will be complete and approximately two years of interval data will have been collected and analysed.

For a start, AIMRO has enabled JEN to prepare for power quality monitoring at the level of customer premises. JEN intends to develop query and reporting tools to enable aggregation of data into meaningful sets of information, and to provide exception reporting to better manage the quality of supply to customers. JEN intends to enhance the AIMRO architecture to provide an engineering user interface for customer quality of supply information and to facilitate investigations into poor power quality performance. JEN's regulatory proposal includes expenditure to enable this functionality.

Renewable energy target scheme

The Commonwealth passed legislation in September 2009 to expand the renewable energy target (**RET**) scheme by setting higher annual renewable energy targets beyond 2010. The expanded scheme will provide that the equivalent of at least 20 per cent of Australia's electricity comes from renewable sources by 2020. The scheme will commence no later than 1 July 2011. The expanded RET scheme has been designed in cooperation with the states and territories through the Council of Australian Governments (**COAG**) and brings the current Commonwealth scheme and existing and proposed state schemes into a single national scheme.

Solar feed-in tariffs

To build on the RET scheme, the Victorian Government has introduced solar feed-in tariffs to encourage customers to establish distributed source of solar electricity throughout the state. Feed in tariffs will be payable by retailers under the Electricity Industry Amendment (Premium Solar Feed-in Tariff) Act 2009 and recovered by a charge imposed on distributors.

Over time, JEN's network will need to adapt to an increasing number of small sources of energy and this creates some interesting new technological challenges.

National hot water strategic framework

The Ministerial Council on Energy's (**MCE's**) national hot water strategic framework provides for the reduction of greenhouse gas emissions associated with water heating. It specifies minimum energy performance standards for water heaters and phasing out of conventional electric resistance water heaters, except where the emissions intensity of the public electricity supply is low, together with a range of information and education measures.

The phase-out of conventional electric resistance water heaters is intended to cover all new homes and established homes in gas reticulated areas from 2010, and new flats and apartments in gas reticulated areas and established homes in gas non-reticulated areas from 2012.

Victorian energy efficiency target scheme

The Victorian Energy Efficiency Target (**VEET**) initiative commenced on 1 January 2009. Phase 1 will continue through 2009, 2010 and 2011. The target for Phase 1 is 2.7 metric tonnes of CO2 equivalent (**Mt CO2e**) of deemed greenhouse gas abatement (**GHGA**) per year in 2009, 2010 and 2011.

VEET requires Victorian energy retailers to obtain and then acquit Victorian Energy Efficiency Certificates (**VEECs**) in proportion to their share of Victoria's total annual residential greenhouse gas emissions.

Most VEET eligible activities will result in reductions in electricity consumption. Consequently, VEET will affect JEN's customer demand in 2009 and over the forthcoming regulatory control period. The effects of this scheme are considered further in chapter 6.

2.8.3 New regulatory requirements

JEN is or is about to be subject to a range of new regulatory obligations that will change its practices and its costs. While Chapter 3 provides a full description, the following sets out some of the new obligations.

Changes to environmental regulation

JEN must dispose of the waste generated by its operations. On 1 July 2009, new Environment Protection (Industrial Waste Resource) Regulations 2009 came into operation. Recent changes by the EPA have increased the costs of disposal to reach their objective of Zero Hazardous waste to landfill by 2020. These new regulations encourage reuse or recycling options and shift risks and costs to JEN.

NGERS reporting

JEN faces new mandatory reporting obligations under the NGERS. NGERS has complex reporting requirements, supported by financial and legal penalties. As a result JEN must engage specialist skills in the form of external auditors to provide assurance and external legal advice to ensure regulations are interpreted soundly and the NGERS reporting is complied with.

AEMC – distribution planning

The Australian Energy Market Commission (**AEMC**) produced its final report on a national framework for electricity distribution network planning and expansion on 28 September 2009. The key elements of the framework are the Distribution Annual Planning Report (**DAPR**), the Demand Side Engagement Strategy (**DSES**) and the Regulatory Investment Test for Distribution (**RIT-D**) process.

The annual planning requirements will introduce a minimum of five-year planning for all assets and activities that would materially affect the performance of the network, including replacement assets. Distribution Network Service Providers (**DNSPs**) will be required to explain any aspects of the forecasts and modelling that have changed significantly from the previous year's report. The DAPR is also to contain regional development plans.

Although the proposed AEMC planning framework builds to an extent on existing processes carried out by DNSP's, it introduces a much more formalised and structured process. It also introduces major new elements such as the DSES and Specification Threshold Test (**STT**) which will require new processes and procedures, including additional information and analysis. JEN anticipates that substantial additional work will be required to introduce the AEMC's new framework and maintain it annually.

Compliance with new safety management system

The Electricity Safety Amendment Act 2007, which comes into effect on 1 January 2010, makes it compulsory for electricity distribution network operators to submit an Electricity Safety Management Scheme (**ESMS**) to Energy Safe Victoria for approval, and to operate in accordance with that scheme. The Electricity Safety Management scheme, or "Safety Case", describes:

- the standards for the design, construction, operation and maintenance of network assets

- the systems to protect persons from risk, and property from damage, associated with network assets.

This mandatory ESMS represents a paradigm shift in regulation away from prescribed regulations mandating a common approach across different networks, to a system underpinned by identifying and managing risks associated with particular assets to a level that is as low as reasonably practicable (**ALARP**). JEN has included expenditure in its forecasts to manage risks under the new ESMS.

3 Regulatory obligations or requirements

JEN's operations and costs are affected by various regulatory obligations or requirements including those dealing with safety, the environment, network design, service performance and reliability, as well as the requirements for provision of direct control services.

This chapter sets out how JEN will address those regulatory obligations or requirements that have a material impact on forecast capital and operating expenditures, in compliance with clauses 6.5.6(a)(2) and 6.5.7(a)(2) of the Rules and RIN clause 3.1(b)(iii), and 4.2(b).

This chapter is structured as follows:

- *Summary* – provides an overview
- *Existing regulatory obligations* – provides a high level overview of the regulatory obligations and requirements to which JEN is subject and highlights the key regulatory obligations and requirements which materially affect the capital and operating expenditure proposals
- *New and anticipated regulatory obligations* – notes regulatory obligations of which JEN is aware that may apply during the forthcoming regulatory control period and where indicated have been incorporated in the capital and operating proposals.

3.1 Summary

JEN is subject to a significant number of regulatory obligations and requirements. JEN's principal electricity distribution related obligations are contained in national electricity legislation (i.e. the NEL, the Rules and associated procedures) and Victorian electricity legislation (i.e. the Electricity Industry Act 2000 and the Electricity Safety Act 1998, and associated regulations, codes and guidelines).

JEN's capital and operating programs have been developed to comply with these obligations.

JEN has also identified a number of new regulatory obligations (or changes to current regulatory obligations) which will be introduced in the remainder of the current regulatory period or in the forthcoming regulatory control period.

3.2 Existing regulatory obligations

3.2.1 Introduction

"Regulatory obligation or requirement" is defined in s. 2D of the NEL. In relation to the provision of network services, it means:

- obligations relating to distribution system safety, reliability or service standards
- obligations or requirements under the NEL or Rules
- obligations or requirements under Victorian or Commonwealth legislation or instruments that impose levies or taxes; regulate the use of land; protect the environment; or materially affect the provision of network services.

3.2.2 Overview of regulatory regime

This section provides a high level summary of the key legislative and regulatory instruments to which JEN is subject in connection with the provision of standard control services in the categories set out in Section. 2D of the NEL.

JEN is subject to electricity industry specific regulation under:

- the NEL, the Rules and applicable procedures made pursuant to the Rules, including the B2B Procedures, MSATS Procedures and Metrology Procedures
- Victorian legislation and regulations made under that legislation, which includes the Electricity Industry Act 2000 and the Electricity Safety Act 1998
- its electricity distribution licence issued by the ESC under the Electricity Industry Act 2000, and codes and guidelines issued by the ESC, including the Victorian Electricity Distribution Code.

Some of the current jurisdictional regulation is moving to the national framework during the forthcoming regulatory control period. Economic distribution regulation (of which this price review process forms part) is currently regulated by the AER in accordance with Victorian regulatory instruments. However, the process for this distribution determination is being conducted under the national regime and it is JEN's understanding that it is intended the national regime will apply in Victoria with effect from 1 January 2011, and that the Victorian regulatory instruments will be transitioned out, as appropriate.

Further, non-economic distribution regulation will be transferred from the jurisdictional regime to the national regime through the implementation of the national energy customer framework (**NECF**) and national customer connections framework (**NCCF**) during the forthcoming regulatory control period.

However, certain matters will continue to be regulated under the jurisdictional regime, including in particular service standards and safety requirements.

Distribution system safety duty

A distribution system safety duty is a duty or requirement imposed under an Act or instrument made under an Act relating to the safe distribution of electricity or the safe operation of the distribution system.

Distribution safety duties are primarily imposed on JEN through the Electricity Safety Act 1998 and regulations and guidelines made under that Act, which deal with matters such as the establishment of an electricity safety management scheme, electric line clearance and bushfire mitigation. JEN is also subject to Electrical Safety Codes of Practice, such as the Code of Practice of Electrical Safety for Work on or Near High Voltage Electrical Apparatus.

Distribution reliability standard

A distribution reliability standard is a standard imposed under the Rules or jurisdictional electricity legislation relating to the reliability or performance of a distribution system.

JEN is subject to the reliability standards set out in chapters 4 (power system security) and 5 (network connection) of the Rules, as well as those standards set out in chapters 4 (quality of supply), 5 (reliability of supply) and 6 (guaranteed service levels) of the Victorian Electricity Distribution Code and guidelines issued by the Essential Services Commission (for example, Electricity Industry Guideline No 11 Voltage Variation Compensation).

Distribution service standard

A distribution service standard is a standard relating to the standard of services provided by a regulated distribution system operator by means of or in connection with a distribution system imposed by jurisdictional electricity legislation or by the AER in accordance with the Rules.

JEN is subject to obligations in relation to the services it provides through the national Rules, in particular, chapter 5 (network connection) and through jurisdictional instruments such as chapter 6 (guaranteed service levels) of the Distribution Code.

Solar feed-in tariffs

Feed in tariffs will be payable by retailers under the Electricity Industry Amendment (Premium Solar Feed-in Tariff) Act 2009 and recovered by a charge imposed on distributors. This will be addressed through the transmission cost recovery control mechanism (see section 14.4.2).

Land

If JEN intends to expand its distribution network over the forthcoming regulatory control period or requires additional rights over land then it will need to comply with the Electricity Industry (Residual Provisions) Act 1993 and the Land Acquisition and Compensation Act 1986.

Environment

In undertaking the provision of standard control services, JEN is subject to Victorian and Commonwealth legislation which protects the environment.

Relevant legislation includes the Planning and Environment Act 1987, Environment Protection Act 1970, Environment Protection and Biodiversity Conservation Act 1999 (Cth), Heritage Act 1995, Aboriginal Heritage Act 2006, National Parks Act 1975, Flora and Fauna Guarantee Act 1988, Wildlife Act 1975 and Forests Act 1958.

3.2.3 Key regulatory obligations or requirements

This section highlights the key regulatory obligations or requirements which materially affect the capital and operating expenditure proposals. Metering related obligations have not been included in this section on the basis that there is no cost recovery for metering under the Electricity Distribution Price Review (other than in respect of un-metered supplies).

Electricity related safety obligations

These obligations mostly fall within the category of distribution of safety duties which are described in section 3.2.2 of this regulatory proposal. Section 4.2 of JEN's Network Asset Management Plan (**NAMP**) provides a more detailed overview of the suite of electricity related safety obligations which are imposed on JEN.

Significant current electricity safety related obligations include those imposed under the following Regulations and Codes:

- Electricity Safety (Installation) Regulations 1999 - these regulations provide for the registration of electrical contractors, the licensing of electrical workers, safety standards for electrical installations and electrical workers, and testing certification of electrical installation work

- Electricity Safety (Bushfire Mitigation) Regulations 2003 - these regulations impose requirements in relation to bushfire mitigation plans including a maintenance regime to inspect and repair electricity infrastructure to minimise the risk of powerlines starting fires. For a detailed description of JEN's bushfire mitigation plan, see section 4.5 of the NAMP

- Electricity Safety (Electric Line Clearance) Regulations 2005 - these regulations prescribe the Code of Practice for electric line clearance and set out the standards and practices to be adopted and observed in tree pruning or clearing in the vicinity of electric lines and keeping vegetation clear of electric lines. They also prescribe management procedures to minimise the danger of electric lines causing fire

- Code of Practice of Electricity Safety for Work On or Near High Voltage Electrical Apparatus 2005 (the Blue Book) - this prescribes safe work practices in maintaining safe systems of work in relation to control of risks associated with work on or in the vicinity of high voltage electrical apparatus in Victoria

- Code of Practice on Electrical Safety for the Distribution Businesses in the Victorian Electricity Supply Industry (the Green Book) – this sets out, amongst other things, safety procedures that apply to employees and contractors of electricity distributors working on or in the vicinity of any electrical apparatus controlled by an electricity distributor

- Electricity Safety (Network Assets) Regulations 1999 - these regulations provide for the safe generation, transmission, distribution and supply of electricity and are the principal regulations governing the design, construction, maintenance and operation of electricity distribution networks in Victoria. These regulations will sunset on 14 December 2009

- Electricity Safety (Management) Regulations 1999 - these regulations provide for the standards with which, amongst other things, electricity safety management schemes must comply, and the procedures for recommending electricity safety management schemes for acceptance. These regulations are due to sunset in December 2009 and be replaced by the Electricity Safety (Management) Regulations 2009. While it is expected that these new regulations will make relatively limited substantive amendments to the existing regulations, the basis on which these regulations are applied in practice will differ from that currently adopted. This is described in more detail below.

Electricity safety management schemes

The Electricity Safety Act 1998, and the regulations made under it, mostly adopt a prescriptive approach to the regulation of activities of electricity companies. The Act does however allow for the voluntary development of an Electricity Safety Management Scheme by, amongst others, network operators. JEN voluntarily implemented an Electricity Safety Management Scheme in June 2004.

However, the Electricity Safety Amendment Act 2007, which comes into effect on 1 January 2010, will make it compulsory for electricity distribution network operators to submit an Electricity Safety Management Scheme to Energy Safe Victoria for approval and to operate in accordance with that scheme. In addition, the Act also provides Energy Safe Victoria with the power to require scheme operators to obtain independent audits of the operator's compliance with its scheme at its own cost. The provisions of the proposed new Electricity Safety (Management) Regulations 2009 will therefore apply to all electricity distribution network operators in Victoria.

JEN's new ESMS, which has been developed in anticipation of the implementation of the new Electricity Safety (Management) Regulations 2009, currently comprises four main components:

1. Network description

The scheme contains a description of the design, construction, operation and maintenance of JEN's distribution network. This is to provide Energy Safe Victoria with sufficient information to enable it to identify JEN's distribution network and assess the risks associated with the safety of the network.

2. Formal safety assessment

All schemes must contain a formal safety assessment and must provide, amongst other things, a description of the method used and investigations undertaken for the formal safety assessment, an identification of hazards and an assessment of risks associated with electrical work carried out on the network.

3. Safety policy, procedures and system

This is the scheme's safety management system and includes JEN's safety policy, the technical standards applicable to the design, construction, installation, operation, maintenance and modification of the network as well as the access authority system, reporting and training requirements.

4. Emergency management procedures.

This is the response plan designed to address all reasonably foreseeable emergencies.

Although the Electricity Safety (Management) Regulations 2009 will not make substantive amendments to the Electricity Safety (Management) Regulations 1999, there will be additional reporting and audit requirements in relation to the new compulsory Electricity Safety Management Scheme. Additional opex costs to comply with the new scheme have been incorporated as a step change in JEN's opex forecast. A number of new capital projects have also been included in the JEN's regulatory proposal as a result of risk assessments carried out under JEN's new Electricity Safety Management Scheme.

Customer connection obligations

Customer initiated connections account for a significant proportion of JEN's capital expenditure. Customer connection related obligations which are imposed on JEN, more detail of which is contained in section 6 of the NAMP, are imposed under:

- JEN's Electricity Licence - the licence imposes a general obligation on JEN to offer connection services and supply to customers if requested to do so by a retailer or customer and to make a connection offer within 20 business days of such request. Additional requirements in relation to the offer are also imposed by the licence

- Victorian Electricity Distribution Code - the code imposes additional requirements in relation to customer connections including obligations relating to the installation and maintenance of metering and associated equipment, energisation and connections without energisation

- Electricity Industry Guideline No. 14, provision of services by electricity distributors - these guidelines impose requirements in relation to, amongst other things, the contestability of connection and augmentation works and the determination of customer contributions to the capital cost of new works and augmentation.

Quality of supply/power

Section 5.4 of the NAMP outlines why quality of supply has become an increasingly important industry issue and the initiatives JEN is undertaking, including through its power quality plan, to ensure that it is able to effectively manage quality of supply on its network in the future.

Quality of supply obligations are imposed on JEN principally through the Electricity Distribution Code which prescribes the voltage, harmonics and monitoring requirements with which JEN must comply. Quality of supply obligations are also imposed on JEN under clause 5.2.3 of the Rules.

In addition, Electricity Industry Guideline No 11 – Voltage Variation Compensation requires distributors to compensate certain customers whose property is damaged due to unauthorised voltage variations.

Network planning and augmentation

Section 7 of the NAMP details the network augmentation process which JEN has adopted to facilitate, amongst other things, compliance with augmentation and network development related obligations in the Rules (clause 5.6.2 – Network development related obligations) and JEN's electricity distribution licence (clause 13 – Other Augmentation Works and clause 14 – Transmission Connection Asset Planning and Augmentation).

Additionally, the Electricity Distribution Code imposes an obligation on JEN to publish an annual Distribution Planning Report which details plans over the next five calendar years to meet predicted demand for electricity supplied through its sub-transmission lines, zone substations and high voltage lines and to improve reliability to its customers.

Reliability of supply

Reliability of supply obligations are contained in Chapter 4 of the Rules.

Key obligations imposed on network service providers include obligations to:

- maintain controls in place to facilitate rotational load shedding and restoration process if there is a prolonged major supply shortage or extreme power system disruption
- operate their networks in accordance with certain power system stability guidelines developed by AEMO.

The key reliability of supply obligations imposed on JEN under Chapter 5 of the Victorian Electricity Distribution Code include an obligation to use its best endeavours to:

- meet targets required by JEN's Electricity Distribution Price Determination (from time to time)
- meet the reliability targets prepared by JEN and published on its website pursuant to clause 5.1 of the Victorian Electricity Distribution Code
- otherwise meet reasonable customer expectations of reliability of supply.

As noted in chapter 16, reliability of supply components will also be included in the STPIS.

Customer service levels

The principal customer service level requirements are currently the minimum guaranteed service levels set out in clause 6 of the Victorian Electricity Distribution Code which prescribe service levels to be met by distributors and the amounts payable to customers for failing to meet those levels. The guaranteed service level obligations relate to appointments with customers (clause 6.1), failure to supply a customer on the agreed date (clause 6.2); and certain unplanned sustained interruptions (clause 6.3).

Customer service components will also be included in the STPIS. As discussed further in chapter 16, JEN proposes that the guaranteed service levels set out in the Victorian Electricity Distribution Code continue to apply to JEN during the forthcoming regulatory control period. In addition, JEN has proposed that the customer service component of the STPIS be limited to response times for answering the telephone in call centres.

3.3 New or anticipated regulatory obligations

Set out below is a list of new or anticipated regulatory obligations that JEN is aware of, which may apply during the forthcoming regulatory control period and which, where indicated, have been incorporated in JEN's capital and operating expenditure proposals. Also refer to the RIN template 4.1 which includes, amongst other things, further details of such new or anticipated regulatory obligations.

New regulatory obligations:

- As of 1 January 2010, there will be mandatory Electricity Safety Management Schemes and audit requirements pursuant to Part 2 of the Electricity Safety Amendment Act 2007, and the Electricity Safety (Management) Regulations 1999 will be replaced with the Electricity Safety Management Regulations 2009. The additional opex costs of complying with the new mandatory scheme have been incorporated as a step change in JEN's opex forecast. A number of new capex projects have also been included in JEN's regulatory proposal as a result of the risk assessment carried out under JEN's new Electricity Safety Management Scheme which it has introduced in anticipation of the above changes in regulatory obligations.

- The Industrial Waste Resource Guidelines, which support the Environment Protection (Industrial Waste Resource) Regulations 2009, state that the reduction of Category B prescribed industrial waste is a focus of the regulations, with the intent of achieving the State government's objective of eliminating industrial waste disposal to landfill by 2020. The additional opex costs for waste management have been included as a step change in JEN's opex forecast.

- There are new information gathering and reporting requirements under the *National Greenhouse and Energy Reporting Act 2007* (Cth). The additional costs of complying with these requirements have been incorporated as a step change in JEN's opex forecast.

Anticipated new regulatory obligations:

- As set out in section 2.2.4 of the NAMP, the AEMC is currently undertaking consultation in respect of a new national distribution planning framework. If implemented, the framework would require considerably more work to satisfy investment criteria, including the completion of a Regulatory Investment Test-Distribution (RIT-D) for all significant projects above a $5 million threshold. The additional opex costs associated with this anticipated change have been included as a step change in JEN's forecast opex.

- There will be obligations for Victorian electricity distributors to improve customer communications during extreme events (this was advocated by the Essential Services Commission in its 14 September 2009 issues paper entitled "Electricity distributors communications in extreme supply events". To the extent known at the time of preparing the forecasts, additional opex costs associated with this anticipated change have been included as a step change in JEN's opex forecasts. However, the ESC's recent draft decision (18 November 2009) indicated that the ESC may impose potential additional obligations that JEN did not anticipate in its forecasts.

- Changes are anticipated to Part 3 of the Electricity Safety (Electric Line Clearance) Regulations. The Minister for Energy has requested advice on the appropriateness of clearance space dimensions, appropriate types of vegetation in the vicinity of power lines and any restrictions that should be placed on vegetation outside of the clearance space. Additional vegetation management costs have been included as a step change in JEN's opex forecast.

- Introduction of Service Target Performance Incentive Scheme - This regulatory proposal includes the calculation of the S Factor targets and an assessment of the capex and opex required to meet those targets.

- JEN anticipates the introduction of National Energy Retail Law, National Energy Retail Rules and associated regulations.

Given the uncertainty around the costs associated with its introduction, JEN is proposing to treat the costs of complying with the Carbon Pollution Reduction Scheme Bill 2009 as a proposed pass-through event in Chapter 15.

To the extent that other currently uncertain opex costs become quantifiable during the course of the distribution determination process, JEN proposes to notify the

AER of any resulting change to its opex forecast. JEN may apply for a pass through of any additional compliance costs arising from new regulatory obligations to the extent not allowed for in the distribution determination.

4 Classification of services and negotiating framework

Section 6.2.1 of the Rules allows the AER to classify a regulated distribution service as a direct control service (including standard control services and alternative control services) or a negotiated distribution service. The AER's proposed classifications are set out in its Framework and Approach Paper (**F&A Paper**). JEN agrees with most classifications proposed by the AER, but in some important areas, proposes alternate classifications.

This chapter identifies those services for which JEN proposes different classifications, and JEN's supporting rationale in compliance with clause 6.2 of the Rules, and clause 2.1 of the RIN.

This chapter is structured as follows:

- *Summary* - provides an overview of JEN's proposed classification of services and supporting rationale
- *AER and JEN's proposed service classifications* – summarises the AER's and JEN's proposed classifications
- *JEN's proposed service classification* – explains JEN's proposed classification of services and rationale
- *JEN's proposed negotiating framework* – summarises JEN's proposed negotiating framework.

4.1 Summary

In developing its proposed service classifications and negotiating framework, JEN has concluded as follows:

- JEN agrees with the AER's proposed classifications, other than the AER's classification of all aspects of competitive and non-competitive components of connection and augmentation services as negotiated distribution services
- JEN proposes to classify all new connection and augmentation works as standard control services. JEN believes that its proposed classification is consistent with current classification of services and is more appropriate under the new regulatory framework than that proposed by the AER
- the AER's proposed classification of all new connection and augmentation works as negotiated distribution services:

- is inconsistent with previous arrangements
- would create an unnecessary administrative burden on JEN and its customers in the provision of high volume, routine connection services
- could result in all customers paying at the outset the full cost of connection assets through connection charges, rather than through a combination of connection charges and ongoing network charges.

4.2 AER's and JEN's proposed service classifications

Table 4-1 highlights the differences between the AER's and JEN's services classification.

Table 4-1: Differences between AER and JEN's proposed service classifications

Services	AER Service group	AER Classification	Proposed JEN classification
Connection and augmentation works for new connections – routine connections: • Single phase connection • 3 phase (direct connected meter) connection • 3 phase (CT meter) connection	Connection Services	Negotiated Distribution Service	Standard Control Service
Connection and augmentation works for new connection – non-routine connections	Connection Services	Negotiated Distribution Service	Standard Control Service

This section, together with the two sets of templates required by the RIN, identifies and explains the differences between the AER and JEN approaches.

4.3 Reasons for JEN's proposed service classifications

There are good reasons for departing from the classification set out in the F&A Paper.

Specifically, the F&A Paper does not correctly interpret the current Victorian arrangements and therefore does not meet requirements of Rules 6.2.1(d) and 6.2.2(d). To require negotiation for routine connection services as proposed by the AER would be impractical, given the high volume of connections (approximately 5,201 per year).

JEN's proposed approach seeks to reflect the nature of services provided more accurately, to avoid unnecessary administrative costs for JEN and customers in relation to high volume routine connections.

The proposed classification:

- is consistent with current practice where:
  - a fixed upfront charge is payable by customers for routine connections with the balance of the costs being rolled into the RAB
  - customers pay an upfront capital contribution for non-routine connections, determined in accordance with ESC Guideline 14, with the balance of the costs being rolled into the RAB
- ensures that costs of connections less up front customer capital contributions are rolled into the RAB.

4.3.1 Current treatment of connection services

Under current ESC regulation, routine connections and non-routine connections and augmentations are treated as *excluded distribution services.* For routine connections, customers pay an up front fixed charge approved by the ESC. For non-routine connections and augmentations, the amount of the initial customer contribution is defined in ESC Guideline 14. The amounts contributed for non-routine connections relate to both the "shallow" and "deep" costs of connection.

In each case (routine and non-routine), the current regulatory framework has provided for the balance of the costs incurred by JEN (net of customer capital contributions) in relation to the connection to be rolled into JEN's asset base.

In its F&A Paper, the AER noted the effect of ESC Guideline 14, with which JEN must comply under the conditions of its distribution licence. Guideline 14 requires distributors to undertake competitive tendering for augmentation works, and provides a formula for calculating initial customer capital contributions to new works and augmentation required as part of a connection offer.

JEN understands that the Victorian Department of Primary Industries has indicated its preference to retain the first of the competitive tendering elements of Guideline 14, and the formula for calculating initial customer contributions. JEN would continue to be bound by Guideline 14 for so long as it remains in place.

4.3.2 Treatment proposed in F&A Paper

The AER's classification of all connection services as negotiable services is not consistent with the current approach, and administratively unworkable given the large volume of routine connection services provided by JEN.

It also effectively requires that all of the costs associated with the connection be recovered from customers as an up front contribution and, accordingly, would result in a significant increase in the costs of these services to customers. Furthermore:

- businesses would be prevented from recovering the full costs of non-routine connections upfront due to the constraints of Guideline 14
- un-recovered costs would not be able to be rolled into the regulatory asset base, which only includes assets that relate to standard control services.

Therefore, the AER's classification would not provide distributors with a reasonable opportunity to recover at least their efficient costs of providing connection services, contrary to section 7A(a) of the NEL.

4.3.3 Proposed alternative classification

Within the classification categories in the Rules, JEN proposes that connection and augmentation arrangements be classified as standard control services.

As occurs now, connection services and charges would be in addition to the network services associated with the ongoing operation and maintenance of distribution assets, which will also be classified as standard control services.

The cost recovery would differ from the treatment proposed in the F&A. Consistent with current practice:

- customers would pay an up front capital contribution which would be fixed in the case of routine connections and determined in accordance with Guideline 14 or other applicable regulatory instrument for non-routine connections
- costs that are met by an up-front customer capital contribution would not be included in the RAB
- the balance of the costs of the assets would be included in the RAB.

JEN proposes that the up-front customer capital contribution be determined:

- for non-routine connections, in a manner consistent with Guideline 14

- for routine connections, as set out in Table 4-2.

Table 4-2: Routine connection charges

Connection Type	Business Hours	After Hours
	Proposed Contribution Exc GST	Proposed Contribution Exc GST
Single phase service connection to new premises (including builder's supply in permanent position)	413.25	979.40
Three phase service connection to new premises with direct connected metering (including builder's supply in permanent position)	499.80	1,065.95
Installation of a service cable for new premises that require Current Transformer connected metering	1,851.80	2,869.55
Provision and connection of Current Transformers for new premises	1,211.15	2,586.10

Note: prices are rounded to the nearest five cents and apply to the 2010 calendar year.

The proposed level of customer contributions reflects JEN's estimate of the standard "shallow" costs of undertaking the routine connection service—i.e. the costs of installing the service line that connects the customer's premise to JEN's network. The costs of a meter for the new connection are explicitly excluded, as these costs are recovered under a separate cost recovery framework for AMI. The detailed connection cost build up is provided in Appendix 16.

In practice, the installation of a meter and the installation of a service line take place during a single service truck visit. There is therefore no workable way to separate the cost of installing a meter from the cost of installing a service line. JEN intends to recover the cost of the service line and the installation costs through customer contributions for routine connections. Under JEN's proposed CAM, the installation costs for a new connection will be allocated to standard control services, which means that those costs will not be included in the actual metering costs to be recovered under the AIMRO cost recovery framework.

4.3.4 Impact on RIN templates

As required by clause 2.2 of the RIN, JEN has provided two sets of filled out regulatory templates—one set in accordance with the classification in the F&A and one set in accordance with JEN's proposed classification.

The two sets of templates necessarily differ. As JEN capitalises the costs incurred in providing connection services, the differences apply to capex only and impact RIN templates 2.1 and 3.1.

In the regulatory template filled out in accordance with the JEN Classification, the following changes have been made:

- Template 6.5—job numbers and customer revenues that relate to connection services have been removed.

- Templates 2.1 and 3.1—amount that related to connection services have been moved from tables that deal with negotiated services to those that deal with standard control services. For ease of reference, the rows named “Load Movements” in Table 1 of each of these templates (which were originally empty, as JEN has no load movement capex) were renamed “new customer connections” and information added that relates to aggregate customer connections capex.

Each change was necessary because the relevant table or row dealt with information relating to standard control or negotiated distribution services. Given JEN’s proposed change to the classification, information that relates to connection services was removed from tables and rows dealing with negotiated distribution services and added to the tables and rows dealing with standard control services.

4.4 JEN’s proposed negotiating framework

This section address clause 6.7 of the Rules.

JEN proposes that services associated with the following categories be classified as negotiated distribution services:

- installing new public lighting assets

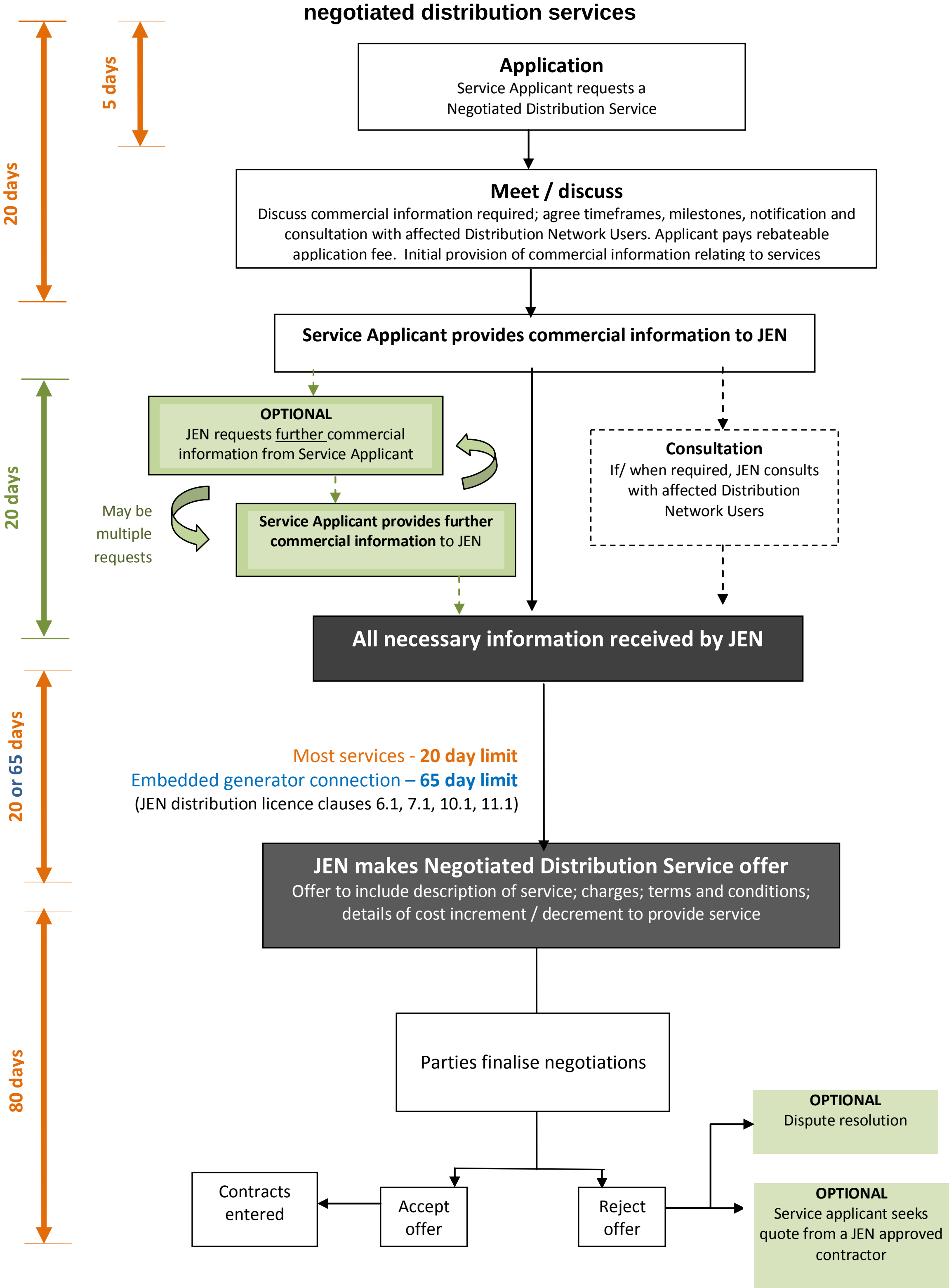
- altering and relocating JEN’s existing public lighting assets

- connecting embedded generators to the distribution network.

Attachment 19 is JEN’s proposed negotiating framework document that has been prepared in compliance with Rule 6.7, and has been developed in the context of existing regulatory obligations that will continue to impact on its processes for negotiating service provision. In particular, JEN notes the time limits required by clauses 6.1, 7.1, 10.1 and 11.1 in JEN’s distribution licence and the provisions relating to embedded generation in ESC Guideline 15.

shows indicative timelines for the negotiating framework.

Figure 4-1: Indicative timelines for JEN's negotiating framework for negotiated distribution services



5 Current performance

To assist the AER in assessing JEN's regulatory proposal, the RIN seeks information on past performance. This chapter provides historical information in compliance with RIN clauses 1.2, 3.6, 3.7, 3.9, 3.10, 4.4, 4.5, 4.6, 5.1, 5.2, 9.5, and 12.1. It examines JEN's performance during the current regulatory control period in the following areas:

- maximum demand, customer numbers and energy consumption
- capital and operating expenditure
- service standards.

This chapter is structured as follows:

- *Summary* – provides a summary of JEN's performance in the current regulatory control period
- *Maximum demand, customer numbers and energy consumption* – discusses JEN's maximum demand, customer numbers and energy consumption performance in the current regulatory control period
- *Capital expenditure* – considers JEN's capital expenditure performance
- *Customer contributions* – considers customer contributions received over the current regulatory control period
- *Operating expenditure* – examines JEN's operating expenditure performance
- *Service standards* – examines JEN's performance against its service standards.

5.1 Summary

In the current regulatory control period:

- JEN's actual and estimated maximum demand, customer numbers and energy consumption are likely to be broadly in line with the ESC final decision for the current regulatory control period. Given the global financial crisis, which emerged in late 2008, it appears likely that the mild outperformance of JEN compared to the ESC decision to 2008 will be counteracted by underperformance in 2009-10.

- JEN has successfully delivered a substantial program of capital works over the current regulatory control period which has led it to exceed the capex allowance made by the ESC by $96.3 million and spend to within nine per cent of its original proposed capital forecast submitted to the ESC.

- JEN has benefitted from economies of scale and scope through outsourcing to a large multi-utility and multi-client asset services provider, Agility, in 2006 to Aug 2007 and JAM since then. By 2010, JEN will have achieved operating efficiencies totalling $54.4 million or 16.9 per cent of the ESC's opex allowance.

- Over the current regulatory control period, JEN's service performance has been affected by many severe weather events. Reliability performance on average has been declining since 2004, a year of mild weather. Initially JEN was still able to deliver performance in excess of the target levels in 2006, despite a significant volume of underground cable faults and poor performance driven by hot weather in January. However, this then deteriorated in 2008, due in part to pole fires, and 2009 due to heat wave conditions and pole fires. These service outcomes have resulted in JEN receiving both rewards and penalties under the ESC's service incentive scheme.

- When considering all outage events, a declining trend in reliability is evident. This is due to an increased number of asset failures, which is typical for an ageing network, and an increase in the impacts of external climate events, particularly pole fires (which occur under certain weather conditions), heat waves and storm events.

5.2 Maximum demand, customer numbers and energy consumption

Table 5-1, Table 5-2 and Table 5-3 show JEN's historic demand over the current regulatory control period.

Table 5-1: Actual/projected maximum demand[7] over the current regulatory control period compared with ESC final decision

Details, MVA	2006	2007	2008	2009	2010
ESC final decision[8]	1,151	1,193	1,224	1,254	1,285
Actual[9]	1,063	1,110	1,186	1,259	na
Variance MVA	-88	-83	-38	+5	
Per cent variance	-7.6%	-7.0%	-3.1%	+0.4%	
Details MW					
Actual/Projected[10]	815.1	867.4	950.0	1,010.9	981.6

Table 5-2: Actual/projected customer numbers over the current regulatory control period compared with ESC final decision

Details	2006	2007	2008	2009	2010
ESC final decision[11] (number)					
Residential	260,822	265,156	269,170	273,260	277,641
Non-residential	30,245	30,763	31,276	31,752	32,234
Total	**291,067**	**295,919**	**300,446**	**305,012**	**309,875**
Actual/projected[12] (number)					
Residential[13]	259,322	262,829	266,878	271,804	276,296
Non-residential[14]	25,766	26,102	26,849	27,308	27,210

[7] Peak demand (non coincident) at the zone substation level

[8] ESC, *Electricity Distribution Price Review 2006-10, October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006, Final Decision Volume 1 Statement of Purpose and Reasons*, October 2006, p. 133.

[9] 2010 not forecast by NIEIR.

[10] This maximum demand is the network coincident maximum demand based on 50 per cent POE. It is the basis of system planning as described in section 6.7.1.

[11] ESC, op. cit. p. 132. These are average customer numbers for each calendar year.

[12] Average customer numbers for each calendar year - 2009 is estimated, 2010 forecast.

[13] Residential numbers exclude hot water meters.

[14] 2006 non-residential numbers restated to correct reporting error.

Details	2006	2007	2008	2009	2010
Total	**285,088**	**288,931**	**293,727**	**299,112**	**303,506**
Variance					
Number	-5,979	-6,988	-6,720	-5,901	-6,369
Per cent	-2.1%	-2.4%	-2.2%	-1.9%	-2.1%

Table 5-3: Actual/projected energy consumption over the current regulatory control period compared with ESC final decision

Details	2006	2007	2008	2009	2010
ESC final decision[15] (GWh)					
Residential	1,169	1,191	1,211	1,228	1,248
Non-residential	3,044	3,073	3,091	3,098	3,109
Total	**4,213**	**4,264**	**4,302**	**4,326**	**4,357**
Actual/projected[16] (GWh)					
Residential	1,203	1,225	1,253	1,255	1,252
Non-residential	3,075	3,154	3,236	3,117	3,088
Total	**4,278**	**4,379**	**4,490**	**4,372**	**4,339**
Variance					
GWh	65	115	188	47	-18
Per cent	1.6%	2.7%	4.4%	1.1%	-0.4%

5.2.1 Comment on current outcomes

JEN notes that:

- Maximum demand (in kVA terms) is 4.2 per cent below the ESC final decision over the years 2006 to 2009.
- Residential customer numbers (excluding hot water meters) are almost exactly in line the final decision over the current regulatory control period.
- Non-residential numbers are on average almost 15 per cent lower than the final decision, but this is partly due to correction of a reporting error for non-residential customers early in the period.

[15] ESC, op. cit. p. 132.

[16] 2009 estimated, 2010 forecast.

- Total energy usage is about 1.8 per cent above the final decision for the current regulatory control period.

5.3 Capex

Table 5-4 shows JEN's historic capex information.

Table 5-4: Actual/projected capital expenditure over the current regulatory control period

	Actual			Projected		
	2006	**2007**	**2008**	**2009**	**2010**	**Total**
System						
ESC final decision	41.0	43.8	43.6	44.5	53.2	226.2
Actual/projected	55.1	57.9	46.9	62.7	71.4	293.9
Variance	14.0	14.1	3.3	18.1	18.2	67.7
Non-system						
ESC final decision	19.1	8.8	11.7	5.1	5.3	50.0
Actual/projected	17.0	18.2	7.2	3.1	33.2	78.7
Variance	-2.1	9.4	-4.5	-2.1	27.9	28.6
Total						
ESC final decision	60.2	52.6	55.3	49.7	58.5	276.3
Actual/projected	72.1	76.1	54.1	65.7	104.6	372.6
Variance	11.9	23.5	-1.2	16.1	46.0	96.3

Note: values include customer contributions.

As shown in Table 5-4, by 2010 JEN will have invested $372.6 million into its network. This exceeds the allowance approved by the ESC by $96.3 million but is within nine per cent of the capital forecast of $344.1 million ($2004) JEN proposed to the ESC during the last price review, or $408.3 million ($2010). JEN has had to self-fund this capital overspend in order to preserve its service levels and network integrity and will rely on the ESC's specified recovery provisions to recover these costs.[17] Section 18.3 details this transitional issue.

The ESC adopted what it characterised as an aggregate level forecasting method. This method escalated JEN's 2001-2005 period expenditure by 30 per cent and apportioned this across the capex categories using the shares of JEN's original

[17] ESC, *Electricity Distribution Price Review 2006-10, October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006, Final Decision Volume 1 Statement of Purpose and Reasons*, October 2006, pp. 270 to 272.

proposal. This method means that no detailed capital program was approved against which JEN can provide a comprehensive explanation of variances.

Notwithstanding this, the following provides a summary of the largest areas of investment by JEN during the current regulatory control period.

JEN invested significantly in its network during the current regulatory control period. Major areas of spend included:

- demand related reinforcements, particularly high voltage augmentation and zone substation augmentation
- new customer connections, particularly business supply projects and dual and multiple occupancies
- reliability maintenance, particularly pole top replacements and zone substation equipment replacements
- IT investment to achieve operational ring fencing between network and retail functions and comply with the ESC's ring-fencing guideline.

5.4 Customer contributions

Table 5-5 shows that JEN's historic customer contributions were more than double the ESC forecast. This reflects that fact that JEN has experienced significantly higher levels of customer initiated capex than forecast by the ESC.

Table 5-5: Actual/projected capital contributions over the current regulatory control period

	Actual			Projected		
	2006	**2007**	**2008**	**2009**	**2010**	**Total**
ESC final decision	5.3	5.3	5.0	5.2	6.0	26.8
Actual/projected	8.3	10.1	11.4	9.1	12.8	51.7
Variance	3.1	4.8	6.4	3.9	6.8	24.9

Note: values exclude public lighting.

5.5 Non-network alternatives

In the current regulatory control period, JEN did not receive a capex or opex allowance that was specifically designated for non-network alternatives. Notwithstanding this, JEN has incurred or will incur costs associated with the following non-network alternatives:

- avoided distribution network changes paid to the Somerton distributed generation facility
- premium feed in tariff rebates for customers with photovoltaic cells who feed energy back into the network.

Over the current regulatory control period, JEN experienced customer growth and related customer initiated capex in excess of the levels forecast by the ESC. Notwithstanding the above non-network alternatives and the fact that JEN published an annual planning report seeking non-network proposals, JEN made no capex deferrals that are attributable to non-network alternatives.

5.6 Opex

Table 5-6 compares JEN's actual and expected opex against the ESC allowance for the current regulatory control period. It shows that over this period JEN has achieved opex efficiencies totalling $54.4 million relative to the ESC allowance.

Key reasons for this 16.9 per cent variance include efficiencies achieved through the amalgamation of JEN's former asset manager Agility with Alinta Asset Management. These include synergies obtained through:

- combined functions such as system control
- lower corporate overhead allocation via WOBCA
- increased level of outsourcing (e.g. meter reading, billing and revenue collection)
- optimisation projects to lower maintenance costs.

Table 5-6: Actual/projected operating and maintenance expenditure over the current regulatory control period

	Actual			Projected		
	2006	**2007**	**2008**	**2009**	**2010**	**Total**
ESC final decision	59.4	60.4	61.6	62.9	64.4	308.6
ESC decision adjusted for out turn demand growth using the ESC determined growth adjustment	59.5	60.3	66.1	67.5	68.9	322.3
Actual/projected	53.5	56.4	47.3	47.9	49.3	254.3
Variance	-5.9	-4.0	-14.3	-15.1	-15.1	-54.4

Notes: The 2010 opex figure is calculated as the EBSS determined value for 2010. This means it is not inclusive of step changes and other factors relevant to the development of JEN's opex forecast, which are set out in section 9.3.

5.7 Service standards

In the current regulatory control period, JEN's service performance has been assessed against the following measures:

- system average interruption duration index (**SAIDI**)
- system average interruption frequency index (**SAIFI**)
- momentary average interruption frequency index - event (**MAIFIe**)
- call centre performance.

Figure 5-1 and Figure 5-2 illustrate JEN's historical reliability performance; the purple bars representing ESC approved excluded events for both upstream events and major event days. The 2009 reliability figures include 9 months of actual and 3 months of forecast.

The red lines in the graph represent the regulatory targets. Historical reliability performance is also provided in a tabular format in Table 5-7.

Figure 5-1: Unplanned SAIDI (ESC exclusion criteria)

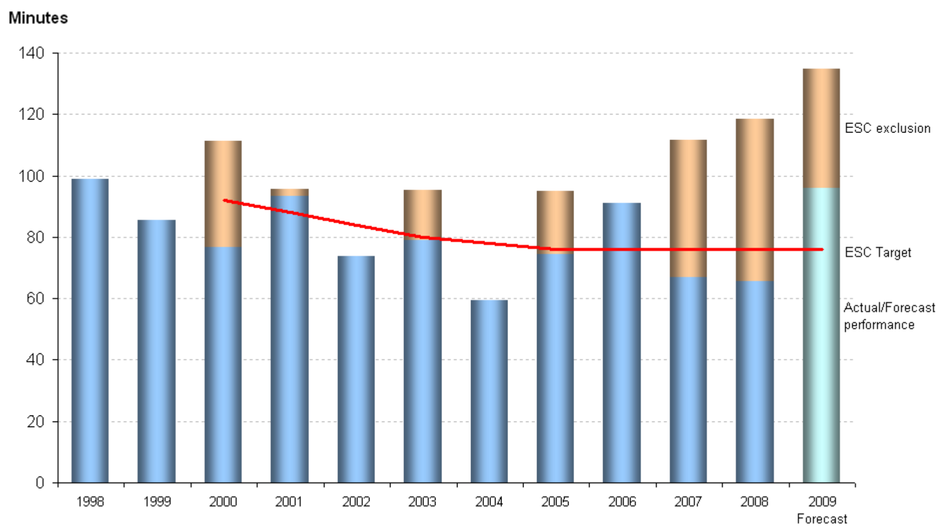


Figure 5-2: Unplanned SAIFI (ESC exclusion criteria)

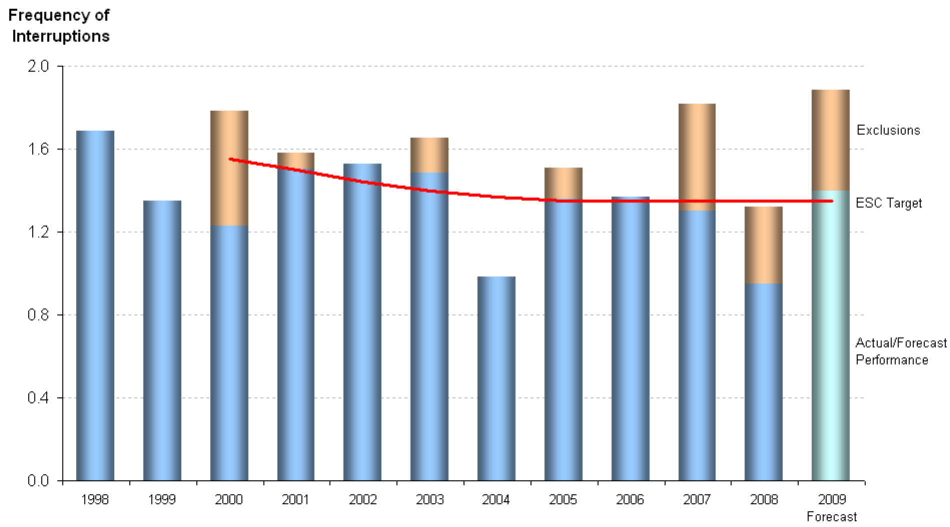


Figure 5-3: MAIFIe (ESC exclusion criteria)

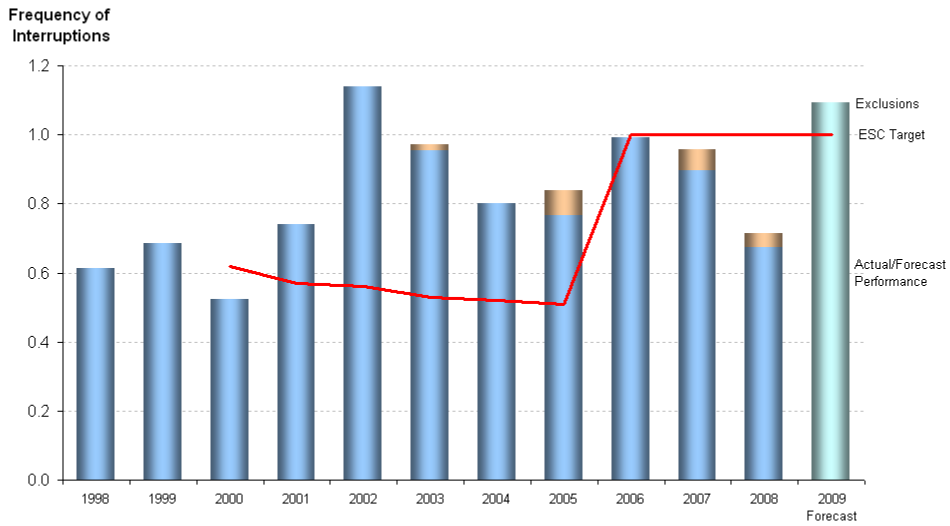


Table 5-7: JEN network unplanned historical performance

Performance measure	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Adjusted for excluded events										
SAIDI unplanned	76.6	93.4	73.7	79.0	59.3	74.5	91.0	66.9	65.6	96.1
SAIFI unplanned	1.23	1.51	1.53	1.48	0.98	1.36	1.37	1.30	0.95	1.40
MAIFIe unplanned	0.52	0.66	1.02	0.95	0.80	0.77	0.99	0.90	0.67	1.09
Unadjusted										
SAIDI unplanned	111.4	95.8	73.7	95.2	59.3	95.0	91.0	111.5	118.4	134.9
SAIFI unplanned	1.78	1.58	1.53	1.65	0.98	1.51	1.37	1.82	1.32	1.88
MAIFIe unplanned	0.52	0.66	1.02	0.97	0.80	0.84	0.99	0.96	0.71	1.09

Figure 5-1 shows historical SAIDI reliability performance, with the purple bars representing ESC approved excluded events (which include both upstream events and major event days). The figure shows that reliability performance as measured by unplanned SAIDI has varied considerably, peaking at a low of 59.3 minutes in 2004, but recently deteriorating to a forecast high of 96.1 minutes in 2009, even after excluded events are removed.

The reasons for variations in underlying performance are:

- 2004 was a year of mild weather, with correspondingly good performance
- 2006 had a significant volume of underground cable faults and many major feeder faults occurring during off-peak hours when resources were stretched. Additionally, the year started with relatively poor performance driven by hot weather for January
- 2008 was a year when weather conditions resulted in significant volumes of pole fires. The storm on 2 April caused significant interruption to electricity supply and was accepted as an exclusion event.
- 2009 is a year of poor performance due to a range of factors, predominantly driven by weather conditions and asset failures. The January heat wave was unprecedented and was accepted as an exclusion event.

It can be seen that the reliability performance of 2009 (9 months actual, 3 months forecast) is likely to be the worst among the last 10 years, even after exclusions are taken into consideration. The major contributors to poor 2009 reliability performance are: heat wave (14.4 minutes), pole fires (9.6 minutes), high winds (6.9 minutes), third party (4.5 minutes), lightning (3.5 minutes) and underground and overhead asset failures (8.6 minutes).

It is important to note that pole fires are caused by a combination of asset conditions (deteriorating crossarm and insulators, and loose pole hardware) and environmental conditions (accumulation of pollutant on insulators, light rain) and are therefore a form of asset failure.

In summary, the declining reliability performance in 2009 is attributed to:

- the external environment the network assets operate in
- increased asset failures in pole tops, overhead conductor connectors and underground assets, which are primarily aged related but may also be linked to the increasingly harsh environment the assets are operating in.

Equipment failure is a significant key cause of network outages. As the network assets age, higher failure rates occur. As a result of increased asset failures, increasing expenditures are necessary on preventative and corrective maintenance as well as on asset replacement to maintain current service levels as measured by SAIDI, SAIFI and MAIFIe.

The largest single influence on the variability of the reliability performance of a mainly overhead network is the environment in which it operates. Weather and associated events such as storms, drought and bushfires together with the effect of third party interference results in large variances in the year to year reliability performance of the network.

An AECOM report assessing climate change impacts indicates that heat wave, high winds and drought are likely to continue, or even get worse, in the forthcoming regulatory control period. In particular, AECOM analysis indicates that JEN's network performance has been adversely affected by high wind events over 100 km/h. With such events forecasted to increase in 2011-15, AECOM estimates the impact to be 13.9 SAIDI minutes per year, reducing to 6.5 SAIDI minutes when AER's new exclusion criterion is taken into consideration, if no specific initiative is taken to counter the impact. The impact of heat waves is to add 0.6 SAIDI minutes per year to the reliability performance. These SAIDI increases are calculated using 2008 as the base year for climate event forecast.

The impact of climate change on reliability performance is therefore material and would require substantial investment to maintain reliability performance at the current level. The detailed plan to address reliability performance in the forthcoming regulatory control period is detailed in Chapter 7 and discussed in JEN's NAMP at Appendix 9.1.

Call centre performance

While JEN exceeded the 75% performance target from 2005 to 2007, as indicated in Table 5.4, JEN made a decision to update their call centre technology as part of the process to outsource its call centre operation to UCMS in May 2007. The previous technology was based on the Cook Announcer system which the ESC decided did not meet the Distribution Code requirement to allow customers the opportunity to talk to an operator when they contact JEN. As a result of the decision to turn off the Cook Announcer System, JEN's call centre performance has been adversely affected and only improved after significant effort. JEN is therefore proposing that the average of 2008 and 2009 call centre performance be used to set the target for 2011-15.

The AER has also proposed a slight change in the definition to exclude calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator from the measure of calls to fault line answered within 30 seconds. Taking this new definition into account, the 2008 and 2009 call centre performance in relation to calls to fault line answered within 30 seconds is shown in Table 5-8.

Table 5-8: JEN network unplanned historical performance

Performance measure	2008	2009 YTD (Sep)
Calls to call centre fault line	122,714	110,711
Calls to fault line not answered within 30 seconds	32,979	25,980
Calls abandoned within 30 seconds	14,430	13,240
Calls to fault line answered within 30 seconds (%)	61%	65%

JEN therefore proposes that the target for "% of call answer within 30 seconds" be set at 63 per cent for 2011-15 as per the new definition stated in the AER STPIS.

6 Demand and customer number forecasts

This chapter sets out JEN's forecast maximum demand and JEN's demand quantity forecast (customer numbers, energy consumption and billed demand) for the forthcoming regulatory control period, in compliance with RIN clause 11 and S6.1.1(3) of the Rules.

The demand forecasts and customer numbers underpin JEN's forecast capex in chapter 8 and opex in chapter 9. The energy consumption and customer number forecasts are also a key input to calculating the X factors in the AER's post tax revenue model set out in chapter 13.

This chapter is structured as follows:

- *Summary* - summarises JEN's maximum demand, customer numbers and energy consumption forecasts
- *JEN forecast maximum demand, customer numbers and energy consumption* – provides a summary of JEN's demand forecasts
- *Basis of demand forecasts* – explains how JEN has established its demand forecasts
- *Method used to develop forecasts* – outlines the approach JEN's expert demand forecasters have applied to forecasts JEN's demand
- *Factors affecting demand forecast* – looks at key assumptions and factors that affect the trends in JEN's demand forecasts over the forthcoming regulatory control period
- *Verification of demand forecasts* – provides a summary of the independent verification of JEN's demand forecasts
- *Use of demand and customer number forecasts* – identifies how and where JEN has relied upon these demand forecasts in its regulatory proposal.

6.1 Summary

JEN has relied upon an independent expert report produced by NIEIR to prepare its demand forecasts. NIEIR's report forecasts that:

- residential energy consumption will reduce from 1,252 GWh in 2010 to 1,151 GWh in 2015 – an average of 1.7 per cent per year

- business consumption fluctuates, but declines from 3,033 GWh in 2010 to 2,808 GWh in 2015 – an average of 1.5 per cent per year

- total energy consumption reduces from 4,339 GWh in 2010 to 4,011 GWh in 2015 – an average of 1.6 per cent per year.

The NIEIR report identifies a significant number of key influences on energy consumption in the JEN region over the 2010-15 period. JEN's regulatory proposal is being submitted amid many new Victorian and Commonwealth Government energy policy developments that will impact energy consumption, including the Carbon Pollution Reduction Scheme (**CPRS**), Minimum Energy Performance Standards (**MEPS**) and AIMRO in Victoria.

Overall, the NIEIR report suggests that these policy developments will succeed in their objective of reducing electricity usage. In addition, these policy changes are occurring in an uncertain economic environment resulting from the global financial crisis of late 2008/early 2009. NIEIR's report indicates that the effects of that crisis are yet to be fully worked out in the Australian and Victorian economies and in the JEN region.

Table 6-1: Forecast demand, customer numbers and energy consumption over the forthcoming regulatory control period

	Forecast year ending					
	2010	**2011**	**2012**	**2013**	**2014**	**2015**
Maximum demand (MW)	981.6	1,002.3	1,026.8	1,051.3	1,077.3	1,093.1
Growth (per cent)		2.1%	2.4%	2.4%	2.5%	1.5%
Customer numbers	305,634	310,957	315,557	319,111	322,702	327,397
Growth (per cent)		1.7%	1.5%	1.1%	1.1%	1.5%
Energy consumption (GWh)	4,339	4,246	4,201	4,105	4,024	4,011
Growth (per cent)		-2.2%	-1.1%	-2.3%	-2.0%	-0.3%

Note: Maximum demand is the network coincident maximum demand based on 50 per cent probability of exceedence (**POE**).

6.2 JEN maximum demand, customer numbers and energy consumption forecasts

Table 6-2 summarises NIEIR's forecasts of maximum demand, customer numbers and energy consumption for JEN over the period 2010-15.

Table 6-2: Summary of NIEIR electricity forecasts over forthcoming regulatory control period (Tables 7.1-7.2 and 8.5-8.6 of NIEIR report)

		Forecast year ending					
		2010	**2011**	**2012**	**2013**	**2014**	**2015**
Maximum demand (MW)							
Maximum summer demand		981.6	1,002.3	1,026.8	1,051.3	1,077.3	1,093.1
Customer numbers							
Residential[18]		278,413	283,329	287,526	291,095	294,852	299,375
Small business		26,128	26,501	26,904	26,894	26,733	26,907
Large business		1,094	1,127	1,127	1,123	1,117	1,115
Total customer numbers		**305,635**	**310,957**	**315,557**	**319,111**	**322,702**	**327,397**
Energy consumption (GWh)							
Residential		1,252	1,237	1,200	1,161	1,144	1,151
Small business		773	730	736	725	714	719
Large business[19]		2,260	2,224	2,211	2,165	2,113	2,089
Total business		3,033	2,955	2,947	2,891	2,827	2,808
Unmetered (including Public lighting)		55	54	54	53	52	52
Total energy consumption		**4,339**	**4,246**	**4,201**	**4,105**	**4,024**	**4,011**
Peak and off-peak energy (GWh)							
Peak energy	Pre-AMI[20]	3,003	2,949	2,906	2,833	2,779	2,776
	Post-AMI	2,881	2,590	2,345	2,206	2,161	2,153
Off-peak energy	Pre-AMI	1,336	1,297	1,294	1,272	1,245	1,235
	Post-AMI	1,458	1,656	1,856	1,899	1,863	1,858
Total energy		**4,339**	**4,246**	**4,201**	**4,105**	**4,024**	**4,011**

Notes: Maximum demand is the network coincident maximum demand based on 50 per cent POE, as developed by JEN (see section 6.7.1). Customer numbers are at year end.

18 Residential numbers exclude off-peak meters.

19 Large business includes traction.

20 The pre-AMI peak/off-peak energy numbers are shown in NIEIR tables 8.5 and 8.6. The post-AMI numbers are derived from the peak/off-peak energy tariff movements shown in NIEIR tables 9.1 to 9.3.

6.2.1 Summary of NIEIR comments on forecasts

NIEIR forecasts residential energy usage to contract by an average 1.7 per cent per year over the forthcoming regulatory control period. The contraction is due primarily to the roll out of interval meters from May 2010, the phase out of resistance hot water heaters, effects of the CPRS, and other policy impacts such as MEPS. Further contraction in the last two years results from the cumulative effects of these policy changes and an expected downturn in the Australian economy in 2013 and 2014.

NIEIR forecasts a decline of 1.4 per cent per year in small business energy usage over the regulatory control period. This contraction is due to the predicted continued high deficits, high interest rates and government spending constraints which slow the Australian economy over the 2013-15 period.

NIEIR forecasts large business energy usage to be relatively static over 2011 and 2012, with an overall contraction of about 1.6 per cent per year in the regulatory period due to an expected downturn in the Australian economy over 2013-2015.

Forecast growth in residential customer numbers by NIEIR (excluding off-peak meters) of about 1.5 per cent per year is slightly lower than growth experienced in the current regulatory control period of about 1.6 per cent per year.

NIEIR forecasts small business customer numbers to show some small growth over 2011-12, but then to fall away slightly in the following years due to an expected down turn in the Victorian and Australian economies in 2014 and 2015. Large business customer numbers are relatively static.

NIEIR quantity forecast figures show the following assumed peak/off-peak split for AMI customers moving from single rate tariffs:

- residential 44 per cent peak and 56 per cent off-peak
- small business 56.5 per cent peak and 43.5 per cent off-peak.

6.3 Basis of demand forecasts

JEN and the other Victorian distribution businesses each engaged an independent demand forecaster, NIEIR to prepare maximum demand, energy and customer number forecasts for the purposes of this regulatory proposal.

NIEIR is a recognised expert in electricity forecasting and is engaged to prepare independent forecasts to support planning by Australian market operators such as VENCorp and NEMMCO (now Australian Energy Market Operator (**AEMO**)).

JEN believes that the independent expert preparation of its energy, customer numbers and peak demand forecasts ensures:

- the reasonableness of method and processes etc required by clause 11.4 of the RIN
- independent verification for clauses 11.5(a) and (b) of the RIN.

JEN has provided as Appendix 7.11 a report from Deloitte, who JEN engaged as an independent expert for the purposes of compliance with RIN clause 11.5(c). Deloitte has verified the use of NIEIR's forecasts by JEN in preparing expenditure forecasts and populating the AER's PTRM.

6.3.1 Independent expert terms of reference

JEN's terms of reference required NIEIR to provide its expert forecasts of the following for each calendar year during the period 2009-19 as a basis for JEN's regulatory proposal.

Demand quantity forecasts

Forecasts for each of the following parameters at a network tariff level:

- customer numbers
- peak energy
- off peak energy
- average billed demand.

Network demand forecasts

Forecasts as follows:

- a summer & winter demand forecast at each terminal station supplying JEN
- as peak demand occurs in summer, an estimate of temperature sensitivity of the demand forecast to 10, 50 and 90 percentile average daily temperature
- the number of new connections split into residential, small business and large business.

NIEIR considerations

NIEIR was required to have regard to following factors that will have an impact of JEN's demand:

- economic growth factors such as new housing activity, household discretionary spending on energy and energy consuming appliances, business production levels, business longevity
- the current economic downturn both globally and locally
- market trends affecting electricity consumption, including but not limited to installing gas heating in lieu of reverse cycle air conditioning, and the impacts of water conservation measures on the consumption of hot water
- Government and other relevant policy impacts
- any other relevant factors.

In arriving at the forecasts, NIEIR was required to consider the impact of major energy and climate change policies, and to quantify the impact of each of these policies.

Additional considerations

NIEIR was also required to consider and quantify the following factors which are reflected in the demand and energy forecasts: demand reset for contract customers, tariff re-assignment and AIMRO effects. Following is a brief discussion of each factor.

- Demand Reset – Over the past number of years many customers have been able to reduce their demand requirement to a level below the billed demand. JEN proposes to reset the billed demand to the maximum demand for each customer on a demand tariff, where there is no contractual arrangement with the customer specifying a contract demand. This is proposed as a one-off automatic reduction to the billed demand reflecting the maximum demand recorded over the 12 month period ending 31 December 2010. This initiative will take effect from 1 January 2011 and will benefit those demand customers who receive the demand reset.
- Tariff Re-assignment – JEN recognises that over the years many customers have changed their load characteristics such that they no longer qualify to remain on their existing tariff. JEN proposes to re-assign commercial and industrial customers to an appropriate tariff where the tariff reassignment will benefit the customer. This initiative will take effect from 1 January 2011.
- As a result of AIMRO, JEN will re-assign all customers with AMI meters to the relevant TOU tariff from 1 Jan 2011. JEN asked NIEIR to take into account its AMI rollout schedule and provide current consumption patterns before the customers were re-assigned to TOU tariffs. JEN asked NIEIR to

indicate possible changes to consumption patterns and impact on its forecasts that would occur as a consequence of this policy.

JEN has provided copies of NIEIR's expert reports in Appendix 7.4 and 7.5. The forecasting method used by NIEIR is broadly described in section 6.4 below. The NIEIR report gives further detail.

6.3.2 Information from JEN

NIEIR drew upon a large body of information provided by JEN, including:

- JEN's published tariff schedule for 2009
- historical monthly quantity data from 1 January 2001 to 31 March 2009 aggregated at the tariff component level
- historical monthly billing data for large business customers over the period 1 January 2001 to 31 March 2009
- historical monthly/quarterly billing data for residential customers over at least the past 18 months
- boundary load data and customer numbers by tariff from 1 January 2001 to 31 March 2009
- historical terminal station half hourly data, including embedded generators over the period 1 January 2001 to 31 March 2009
- a listing of large business customers who intended to cease production in the near future, or have reduced their consumption considerably in recent years; also new large business customers who have increased consumption considerably in recent years, or who intended to increase consumption considerably in the near future
- JEN's AIMRO rollout schedule
- details of JEN's proposed demand reset
- details of JEN's proposed approach to tariff reassignment.

6.4 Method and assumptions used to develop forecasts

This section outlines the key methodologies and modelling assumptions which NIEIR employed in developing the forecasts for JEN's regulatory proposal (see sections 5 and 6 of the NIEIR report for electricity sales and customer numbers in Appendix 7.4[21]).

6.4.1 Overall modelling approach

The centrepiece of the modelling method was the application of NIEIR’s state and industry based economic projection models to the JEN region for JEN’s 2008 actual results. This was used for customer number and energy forecasts, and also contributes to calculating the maximum demand forecasts. The economic models are discussed in more detail in section 6.5.3.

6.4.2 Peak demand projection

NIEIR has developed a method for modelling and forecasting summer and winter peak demands. The model developed by NIEIR is known as PeakSim. The output of this model is provided to JEN in the report at Appendix 7.5.

The PeakSim model has evolved out a number of lines of research at NIEIR. The key initial research began several years ago with a request to provide greater information about the probabilistic nature of seasonal maximum demands. This research pulled together earlier work undertaken by the National Institute in the 1990s and work done by various planning body in Australia and around the world.

The PeakSim model generates probability distributions of peak demand from synthetically generated distributions of temperature and demand. This contrasts with more deterministic models that conditions peak demand forecasts on given temperature levels. A key driver of PeakSim's probabilistic projections is growth in temperature sensitive load which is primarily driven by air conditioning sales. NIEIR monitors and forecasts air conditioner sales and this information is incorporated into the PeakSim model.

The PeakSim model uses half-hourly demand and temperature data, (ideally) spanning at least 10 years. Each half-hourly period during the day is modelled separately to capture the intra-daily dynamics between demand and temperature. Temperature insensitive load is modelled using economic and industrial indicators.

Synthetic distributions of demand for each half hour period are generated from the estimated models using synthetically-generated temperature and residual series. Synthetic temperature series are generated from historical temperature data using sampling methods that preserve the observed patterns in the historical data and allow for the effects of urban and global warming on recent and future climatic conditions. Similarly, synthetic residuals series are generated using sampling methods that ensure consistency with the model structure and the historical events.

[21] National Institute of Economic and Industry Research, *Electrical sales and customer number forecasts to 2019 for the JEN electricity region*, November 2009.

The PeakSim model outputs thousands of synthetic demands for each half hour period over each forecasted season. Probability of exceedence levels are drawn directly from this simulated data. In additional to the conventional metrics of 10 per cent, 50 per cent and 90 per cent probability of exceedence levels, the PeakSim model can generate projections for the full probability spectrum.

In order to arrive at a set of maximum demand numbers to drive a capex forecast, JEN has contrasted its own demand forecasts produced on a bottom-up basis with the top-down set prepared by NIEIR. The result has been that, for the reasons outlined in section 6.7.1, JEN has adopted a different starting point for the maximum demand forecast to that used by NIEIR. However, JEN has maintained the annual growth rates calculated by NIEIR in its report to JEN.

For purposes of tariff pricing incorporated in the PTRM, JEN has used NIEIR's demand quantity forecasts.

6.4.3 Key economic inputs to NIEIR electricity model

NIEIR's demand forecasts were predicated upon the most likely medium term outlooks for the Australian and Victorian economies in the third quarter of 2009. Table 6-3 shows the key Victorian economic inputs used by NIEIR in determining JEN demand forecasts.

Table 6-3: NIEIR economic forecast Victoria – macroeconomic aggregates and selected indicators (per cent change) (Table 3.2 NIEIR)

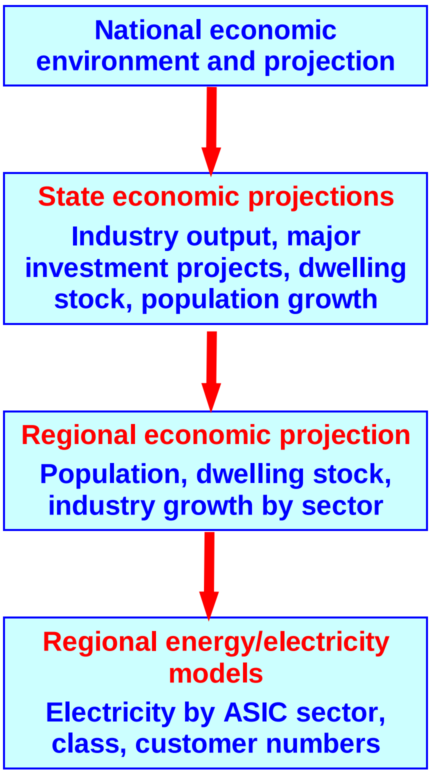
	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	Compound growth rate 2008-09 to 2014-15
Private consumption	0.5	0.9	1.6	3.5	3.3	1.1	0.1	1.7
Private business investment	-6.6	-10.2	18.9	16.8	5.2	3.5	-5.1	4.3
Private dwelling investment	6.3	5.4	4.2	-6.3	-6.6	-1.5	12.1	1.0
Government consumption	2.9	3.4	3.6	1.9	2.0	3.8	3.4	3.0
Government investment	21.0	25.3	2.2	17.2	-1.8	1.5	6.2	8.0
State final demand	0.5	0.6	4.6	5.3	2.6	1.9	0.5	2.6

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	Compound growth rate 2008-09 to 2014-15
Gross state product	-0.4	1.2	2.2	4.4	2.0	0.2	0.0	1.6
Population	1.7	1.5	1.3	1.2	1.1	1.2	1.2	1.2
Employment	1.4	-2.9	0.3	2.3	2.2	0.6	-0.6	0.3

NIEIR used its Victorian regional model to develop economic projections for the JEN region to 2019. The regional model estimates gross regional product by industry across Victorian statistical divisions and local government areas.

Key indicators at the regional level were population, dwelling stock and gross regional product by industry. Figure 6-1 demonstrates NIEIR's modelling approach.

Figure 6-1: NIEIR's regional energy model (NIEIR figure 5.1)



6.4.4 The outlook for the JEN region to 2019

This section summarises the baseline projections for population, dwelling formation and gross regional product for the JEN region to 2019.

- on average, population growth in the JEN region is 0.3 percentage points below the Victorian population projection of 1.2 percent per annum over the 2009 to 2019 period.

- the total dwelling stock in the JEN distribution area is projected to grow by an average rate of 1.5 per cent between 2009 and 2019. This is 0.4 percentage points below the projected growth rate for Victoria and reflects urban infill and growth in the Hume Corridor within the JEN region. This represents growth between 2009 and 2019 of around 37,000 dwelling units

- total gross regional product for the JEN region is forecast to grow by 1.4 per cent between 2009 and 2019, 0.4 percentage points below the Victorian average growth rate.

The JEN region represents 8.3 per cent of Victorian gross state output, and has a large hub of road and air transport services and infrastructure. Figure 6-2 shows the expected growth areas in the JEN region.

Figure 6-2: JEN network growth areas

Commentary on business energy projections

NIEIR used its existing JEN electricity forecasting model to drive the business energy projections. This model is an industry based model which uses the

ABARE[22] energy demand data and NIEIR's projections of gross state product and output by industry along with other variables. The industry classifications used by NIEIR are based on the Australian Standard Industrial Classification (**ASIC**), and NIEIR ensures concordance between JEN customer class categories and ASIC industry categories. JEN provides data for NIEIR to update this model annually to determine JEN's demand quantity forecasts for inclusion in its annual tariff proposal.

JEN provided NIEIR with business sales data on a customer by customer basis. Using the business name and cross checking against yellow pages and other listings, NIEIR industry coded all large business customers in the JEN region. There were some 1,400 large business customers in the JEN distribution area, representing nearly 60 per cent of total JEN business energy sales.

For medium customers, NIEIR similarly industry coded a sample of customers, and used this sample to estimate the ASIC distribution of sales and customers in the JEN area. Commercial customers were also separated out by industry.

6.5 Other factors and assumptions affecting demand forecasts

NIEIR's expert reports provided in:

- Appendix 7.4 for customer numbers, energy usage and billed demand
- Appendix 7.5 for maximum demand.

The reports set out all relevant assumptions and factors affecting their forecasts and their forecasting methods. These include factors such as weather normalisation, usage profiles, and policy and market developments.

At the time NIEIR was preparing its projections, a number of federal and state government policies were having (or were soon to have) major influences on electricity prices and demand in Victoria. NIEIR discusses these extensively in chapters 5 and 6 of Appendix 7.4. The following is a summary of key factors which NIEIR evaluated.

6.5.1 Existing and new residential customer usage

NIEIR's econometric models of residential sales link sales growth with real income per capita, real and relative prices and weather conditions. These general econometric regression models do not allow NIEIR to take account of federal and state government policies that will directly affect energy use by JEN households.

[22] Australian Bureau of Agricultural and Resource Economics.

The impact of energy policies requires separating residential customers into existing customers and new customers.

Given the billings database information provided by JEN, NIEIR was able to determine average annual energy consumption by dwelling for consumption years 2006 and 2007.

Table 6-4: Average residential electricity usage (kWh) old and new customers in 2006 and 2007 excluding hot water (Table 5.4 NIEIR)

Average residential customer usage – existing and new customers	
Existing residential customers in 2006	4,527
New customers in 2007	4,365

New residential customers consume on average around 160 kWh per year less than existing customers. This reflects a number of interacting trends and policy factors which are detailed at length in Appendix 7.4 and discussed further below. Section 6.12 of Appendix 7.4 quantifies the annual policy impacts on total energy for existing and new dwellings in the JEN region to 2019.

6.5.2 Electricity usage in Victoria

Every three years since 1994, the Australian Bureau of Statistics (**ABS**) has produced information relating to domestic energy use by conducting a monthly Labour Force Survey (**LFS**) supplemented by an Energy Use and Conservation Survey (**EUCS**). The latest is March 2008.

The EUCS covers a range of issues including energy sources, appliances and energy saving measures used in households. Despite possible sampling and other errors, it provides a useful overall picture of electricity usage by households in Victoria. NIEIR has analysed the EUCS data extensively in section 5.3 of their report. Major conclusions are that:

- the dominance of gas for water and home heating is clear in Victoria
- historically, the majority of solar systems in Victoria have been solar-electric, However, the trend for electric boosters is on the downturn, steadily decreasing since 1999. Gas-solar has been on a steady rise with 44.7 per cent of solar hot water systems boosted by gas systems in 2008 (a higher proportion than electric-solar).

6.5.3 Electricity prices and the CPRS

On 15 December 2008, the Australian Government released a White Paper on the CPRS. This paper confirmed that an emissions trading scheme is to be introduced by 2010-11. The White Paper outlined the final design of the CPRS, and a target range for reducing carbon pollution.

It was announced in May 2009 that the introduction of the CPRS has now been delayed to July 2011, and permits would be capped at $10 per tonne in 2011-12. The full market will commence in July 2012.

NIEIR's assessment of the White Paper and the implications for carbon permit prices and electricity prices are provided in section 5.2 of the NIEIR report.

6.5.4 Weather normalisation

Section 5 of NIEIR's report details the normalisation model used to weather normalise energy consumption.

The objective of normalisation was to put energy consumption data on an equivalent basis, so that cross-year comparisons can be performed. That is, so that long term trends can be identified.

A common way to measure heating and cooling requirements is by calculating heating and cooling degree day indices.

A heating (cooling) degree day (**HDD** and **HCD**) measures the number of degrees below (above) the threshold temperature of 18 on a day. In NIEIR's normalisation model, the temperature variable was measured using average daily temperature – i.e. the arithmetic mean of daily minimum and maximum temperatures derived from readings taken at the Bureau of Meteorology's Melbourne Regional Office station. Monthly energy consumption was then normalised to normal seasonal temperature.

The normal seasonal temperature, or the 'temperature standard', was based on historical records of monthly totals for HDD and CDD (separately). NIEIR defined the standard HDD or CDD totals for each month by a linear trend of the respective month's HDD and CDD totals over the past 50 years. However, as temperatures have warmed over the past few decades, consumer's perception of what is cold weather has also adjusted and this adjustment has been taken into account.

The NIEIR report in Appendix 7.4 provides further detail on this normalisation.

6.5.5 Policy effects on residential energy consumption and peak demand

In chapter 6, NIEIR outlines and forecasts the effects of a range of energy efficiency and greenhouse gas abatement measures on future electricity consumption and peak demand in the JEN area, focusing mainly on measures affecting residential consumption and peak demand. NIEIR also quantified the effects of certain policy measures on commercial energy usage and peak demand.

The policy measures encompass national measures, such as MEPS and the federal insulation program and state/territorial policy measures, such as building standards. In many instances, policy impacts have been estimated for Victoria and then proportionally allocated to JEN distribution.

NIEIR has estimated the effects of policy measures in both energy (GWh) and demand (MW) terms. This section presents a high-level view of the extensive material in chapter 6 of NIEIR's report.

The policy measures NIEIR considered are:

1. MEPS –lighting
2. CPRS
3. eRET
4. standby power
5. insulation
6. photovoltaics
7. VEET
8. hot water
9. MEPS - air conditioning
10. six- star building standards
11. AIMRO
12. electric cars.

The NIEIR report for electricity sales and customer numbers in Appendix 7.4 show the annual savings anticipated for each policy measure between 2009 and 2019. These are long-lasting savings, which are expected to offset future consumption/demand going forward. Electric vehicles are negative to show that they are in effect an addition to electricity consumption as opposed to the rest of the policies which are expected to reduce the load.

The cumulative effects on JEN's network from these policies in the 2009 to 2015 period are (in total):

- effect on total energy: a reduction of 282 GWh

- effect on summer peak: a reduction of 26.4 MW
- effect on winter peak: a reduction of 48.2 MW.

Table 6-5 shows the annual (cumulative) effects of the above policies on JEN energy consumption.

Table 6-5: Cumulative policy effects on residential energy consumption JEN area (GWh) (Aggregate of NIEIR Tables 6.2 and 6.5)

	2009	2010	2011	2012	2013	2014	2015
MEPS lighting	17.8	35.5	53.3	71.0	81.7	85.2	88.8
Standby power	0.0	0.0	3.3	9.8	16.3	20.6	22.5
Insulation	2.7	8.1	13.5	16.2	16.2	16.2	16.2
Photovoltaics	1.2	2.1	2.6	3.1	3.6	3.9	4.2
VEET	1.6	3.8	6.0	8.2	10.4	13.1	14.8
Hot water	0.7	2.1	5.6	8.9	12.3	15.6	18.7
MEPS air cond.	0.0	0.3	1.0	1.7	2.6	3.3	4.0
6 star building	0.0	0.0	0.0	0.2	0.5	0.8	1.1
AIMRO	0.0	0.0	14.7	51.8	92.9	114.4	117.3
Electric cars	-0.4	-1.2	-2.1	-2.9	-3.7	-4.6	-5.4
Total impact	**23.6**	**50.7**	**97.8**	**168.0**	**232.6**	**268.6**	**282.2**

Note: Positive numbers indicate a reduction in consumption, while negative numbers indicate an increase in energy consumption.

The most significant cumulative policy effects in the above table result from MEPS applied to lighting and from AIMRO. Some observations on these effects from the NIEIR report are set out below.

Effect of MEPS on lighting

Historically MEPS have been applied to electric appliances and equipment under the National Appliance Energy Efficiency Program (**NAEEP**). What MEPS has done is remove the lowest energy efficiency appliances and equipment from the market, thus conferring cost effective benefits to customers and to the energy system.

In the Victorian residential sector virtually all electricity use is or will by 2013 be subject to:

- MEPS and energy labelling

- increased electricity prices under the CPRS
- enhanced household environmental concerns.

In November 2009 a MEPS for lighting will commence. This will remove most incandescent light globes (general service lamps) and some low voltage halogen (downlights, reflector bulbs) from sale. The MEPS will initially be set at a minimum of 15 lumens per watt (incandescent globes are about 7 lumens per watt).

NIEIR estimated the reduction in energy and peak demands using the dwelling stock estimates, an average number of lights per household, a usage rate and an average watt input. This is after allowing for the fact that many Victorian dwellings already have energy efficient light bulbs in place. On this basis, the energy saving in the JEN region is forecast to be 98 GWh in total over the ten years 2009 to 2019. In addition to the savings in the household sector, there are also lighting savings projected for the commercial and public lighting sectors.

AMI rollout

Starting in September 2009, approximately 2.5 million new AMI meters will be rolled out over a four year period. These meters will allow Victorian customers to better manage their energy use by providing more detailed information about their consumption with the opportunity to save money on their power bill and reduce greenhouse gas emissions.

The planned rollout of the meters in Victoria is as follows:

- 2009-10: 350,000
- 2010-11: 1,050,000
- 2011-12: 1,750,000
- 2012-13: 2,100,000

In section 6.9.2 of its report NIEIR note that the benefits and impacts of AMI and time of use pricing (including customer response) have been researched through various pilot pricing studies and also some experiments incorporating AMI and other advanced technology.

The Brattle Group recently surveyed the evidence from the 15 most recent experiments with dynamic pricing of electricity. They found conclusive evidence that households (residential customers) respond to higher prices by lowering usage[23]. Across the range of experiments studied, time-of-use rates induce a drop

[23] Ahmad Faruqui and Sanem Sergiei, *Household Response to Dynamic Pricing of Electricity – A Survey of the Experimental Evidence,* The Brattle Group, 10 January 2009.

in peak period demand that ranges between three to six percent, and critical-peak pricing tariffs induce a drop in peak period demand that ranges between 13 to 20 per cent.

Some other studies also note average energy use reductions achieved in a range of other international contexts[24]:

- Carbon Trust, UK: 5 per cent - 12 per cent
- Sustainability First (21 studies), UK: 5 per cent - 14 per cent
- Hydro One, Canada: 7 per cent - 10 per cent
- Energy Australia: 6 per cent - 8 per cent
- Energy Futures Australia: 4 per cent - 10 per cent

In particular, Energy Australia started a Strategic Pricing Study in 2005 in Sydney. The study tested seasonal, dynamic, and information only tariffs and involved the use of in-house displays and online access to data. In November 2008, Energy Australia reported that it has over 400,000 interval meters installed and 150,000 customers were on TOU tariffs.

In estimating the impact for Victorian distribution business, NIEIR is taking the conservative view and using the results of the most relevant and local study (Energy Australia, NSW), NIEIR forecasts an 8 per cent reduction in energy demand for Victoria due to AIMRO. Some factors which need to be considered in the context of estimating the impact in Victoria as opposed to NSW, are demographic, climatic and economic differences between the states.

Based on the expected roll out schedule of JEN distribution region, and using a forecast average consumption per customer, NIEIR forecasts the savings due to AIMRO in energy in the JEN region between 2009 and 2019 to be 117 GWh. Installation of smart meters has the potential to reduce maximum demand quite substantially, with a forecast of savings in JEN distribution region summer maximum demand of 8.4 MW by 2019 and 12.5 MW in the JEN winter maximum.

6.6 Verification of forecasts

As noted in section 6.4 above, JEN engaged NIEIR as an independent demand forecaster to prepare its realistic demand forecasts.

NIEIR was founded in 1984 as a private economic research and consulting group serving clients in the public and private sectors. NIEIR clients include many of

[24] Energy Futures Australia for Total Environment Centre, *Advanced Metering for Energy Supply in Australia*, 2007, pp. 57 to 61.

Australia's largest and most dynamic corporations as well as all levels of government (including a major role in preparing material for the annual Statement of Opportunities for NEMMCO and the Western Australian Independent Market Operator).

JEN relies on NIEIR to update its demand quantity forecasts on an annual basis for tariff setting and augmentation planning purposes.

6.7 Use of demand and customer number forecasts in JEN's regulatory proposal

JEN engaged Deloitte to independently verify how JEN used its demand forecasts in determining its capex and opex forecasts, and the relevant inputs to the PTRM.

Deloitte concluded that there were no exceptions between the manner in which JEN had described its calculations relating to capex and opex forecasting based on NIEIR data and the corresponding model calculations. A copy of Deloitte's verification statement is provided in Appendix 7.11.

A description of how JEN used the demand forecasts is also provided in the following sections.

6.7.1 Capital expenditure

Network reinforcement

JEN's forecast customer initiated capex is derived through an analytical process that combines economic forecasts of JEN's customer base with the unit rates that JEN anticipates for discrete capital works activities.

The most critical input to the network augmentation planning process is the electricity maximum demand forecasts. The process undertaken to prepare these forecasts involves two complementary sets of demand forecasts being prepared annually, one by JEN's network planning and development group (**NPDG**) and the other by NIEIR.

- NIEIR prepares forecasts of maximum demand for the JEN distribution area. These forecasts include a summer demand forecast at each JEN terminal station and an estimate of temperature sensitivity of the summer demand forecast .The forecasts are based on the economic outlook for Victoria and the JEN supply area, government policies which impact on electricity demand and consumption, and variations in temperature patterns.

- JEN's NPDG develops forecasts using a 'bottom up' approach reflecting localised trends and drivers that influence load growth within the network. These drivers include known future loads, local knowledge such as proposed major industrial and commercial developments, predicted housing and industrial lot releases, proposed embedded generation and other items such as economic forecasts and council planning.

Prior to finalisation and application of the forecasts, JEN compares its bottom-up forecast against NIEIR's top-down forecasts and any material discrepancies are investigated, with the forecasts adjusted if necessary to ensure consistency and accuracy. JEN's practice is to adopt its bottom-up forecast for the purpose of planning its network, as this provides detailed information at the feeders and zone substations levels at which augmentation occurs.

In respect of the current price review, JEN's bottom-up 10 per cent POE forecast is consistent with NIEIR top-down 10 per cent POE forecast from 2010 to 2016. At the 50 per cent POE level, JEN's bottom-up forecast is t 2.8 per cent higher than NIEIR top-down forecast. This is due to the difference in the starting point in 2009, where NIEIR has not taken into account a large number of distribution transformers outages during times of maximum demand in January 2009 caused by the heat wave.

JEN is proposing to adopt its view of the starting point for NIEIR's forecasts in its regulatory proposal but thereafter to use the same annual growth rate for maximum demand as calculated by NIEIR. Thus, the JEN and NIEIR forecasts are substantially aligned and would produce similar capex outcomes.

Table 6-6 provides a comparison between the two sets of forecast for network coincident maximum demand at 50 per cent POE.

Table 6-6: Comparison of JEN and NIEIR maximum demand forecasts at 50 per cent POE

	Forecast year ending					
	2010	**2011**	**2012**	**2013**	**2014**	**2015**
JEN maximum demand forecast (MW)	981.6	1,002.3	1,026.8	1,051.3	1,077.3	1,093.1
NIEIR maximum demand (MW)	957.9	971.2	993.3	1,023.3	1,050.8	1,063.9

The outcome of the network augmentation planning process described above is a detailed asset investment plan to ensure that the JEN network has adequate capacity to meet anticipated maximum demand, even under extreme summer conditions using a probabilistic approach to planning the distribution network.

Customer initiated capex

JEN has relied on NIEIR's customer forecasts as an input to its customer initiated capital planning as described in section 6 of the NAMP attached at Appendix 9.1.

6.7.2 Operating expenditure

JEN has relied upon the NIEIR maximum demand, customer number and energy consumption forecasts to determine the growth related element of its opex forecast. JEN has employed the weighted opex growth rate for consumption, customer connections and maximum demand determined by the ESC for the purposes of the current regulatory period to roll forward its base opex costs for growth using the NIEIR forecasts. This is described in section 9.3.4.

7 Target performance outcomes

This chapter describes JEN's approach to network planning and management and the target performance outcomes that it aims to achieve over the forthcoming regulatory control period. This information provides background to the capex and opex forecasts, in compliance with clause 6.1.1 of the Rules. RIN clauses 3.1 and 4.2 are set out in chapters 8 and 9 respectively.

This chapter is structured as follows:

- *Summary* - provides an overview of the key challenges faced by JEN and JEN's resulting target outcomes over the forthcoming regulatory control period

- *Target performance outcomes* – sets out JEN's target performance outcomes over the forthcoming regulatory control period

- *JEN's network planning framework* – provides an overview of JEN's network planning framework

- *Key challenges addressed by the network asset management strategy, processes and plans* – identifies the key challenges facing JEN over the forthcoming regulatory control period

7.1 Summary

Key points of this chapter include:

- JEN's approach to network asset management is designed to support its corporate goals and objectives, which are aligned with the capital and operating objectives, criteria and factors of the Rules.

- Its network strategies are aimed at meeting forecasted customer electricity demand, complying with regulatory obligations, and maintaining quality, reliability and safety standards in the face of increasing customer expectations, while managing aging infrastructure and the impacts of climate change.

- JEN's approach for the forthcoming regulatory control period is articulated in its NAMP and its subsequent Capital and Operational Work Plan (**COWP**), along with JEN's IT Strategy and Asset Management Plan (**ITP**) (see Appendices 9.1 and 9.2).

7.2 Target performance outcomes

JEN's network asset management strategy, processes and plans have been developed to deliver JEN's overall strategic objective and deliver outcomes in relation to reliability, utilisation, customer service, safety and asset condition.

Section 5 of the NAMP explains how JEN's target performance outcomes flow from a robust process, which includes detailed analysis and risk assessments. The key target outcomes reflected in the NAMP and associated COWP performance are discussed below.

7.2.1 Service performance targets

As discussed in section 5.7, JEN's customers have experienced deterioration in reliability performance in recent years, in part due to external factors (wind storms, drought, heat wave), as well as an increase in asset failures.

Consistent with the AER's STPIS, JEN plans to maintain reliability performance at the current five year average historical level[25], to deliver improved customer service during major emergency events, as well as continue to foster a positive customer service business culture. JEN may also undertake additional targeted improvements over the next regulatory period where these can be justified under the STPIS.

Customer average reliability performance as measured by raw unplanned SAIDI has been declining since 2004 when excluded events are taken into account. Even after discarding excluded events, reliability performance for 2009 is likely to be the worst among the last 10 years (see section 5.7). The decline in reliability performance in 2009 is attributed to the external environment the network assets operate in, as well as the continued trend of increasing asset failures.

Power quality is becoming an increasingly important issue for electricity customers, electrical equipment suppliers and manufacturers. Unlike reliability which deals with the presence or absence of electricity supply, power quality affects the correct operation of electrical equipment, and in some cases, its life expectancy.

Table 7-1 shows JEN's target service levels based on the past 4 years of historical performance and a forecast for 2009 performance.

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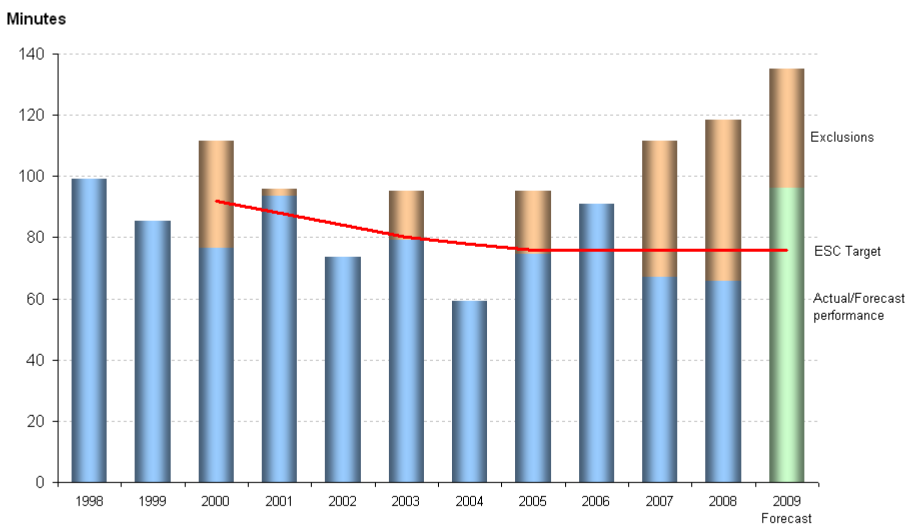
[25] Call centre performance is based on an average of 2008 and 2009 performance, adjusted for the AER's definition of call performance.

Table 7-1: Service performance targets for forthcoming regulatory control period

Service performance measures	Target
Total customer minutes off supply (SAIDI)	89.4
Unplanned customer minutes off supply (SAIDI)	76.3
Planned customer minutes off supply (SAIDI)	13.2
Unplanned sustained interruption frequency (SAIFI)	1.28
Unplanned interruption duration (CAIDI)	60
Momentary interruption frequency event (MAIFIe)	0.94
Calls to fault line answered within 30 seconds	63%

As shown in chapter 5 of JEN's NAMP, projects and programs have been developed to arrest the current deterioration in network performance and take account of the key drivers, which will put continued pressure on the performance of JEN's network assets over the forthcoming regulatory control period. JEN's forecast of reliability performance for 2011-15 is shown in Figure 7-1 below.

Figure 7-1: Unplanned SAIDI (AER exclusion criteria)



Note: The bars coloured in tan represent exclusion events based on AER criteria.

JEN has also set target outcomes for power quality, asset utilisation, customer service measures, safety indicators and asset condition indicators over the forthcoming regulatory control period.

7.2.2 Power quality

JEN's aim of the power quality plan is to maintain power quality levels within current performance levels. JEN will do this by:

- addressing any emerging issues identified as being associated with power quality with appropriate mitigations
- minimising interruptions to customers due to network induced voltage disturbances
- minimising damage to customer and network equipment caused by power quality issues
- reducing the level of network losses generated by voltage unbalance and harmonics
- encouraging industry development of power quality standards and strategies.

JEN's target for power quality performance is shown in Table 7-2.

Table 7-2: Power quality targets for forthcoming regulatory control period

Power quality performance measures	Target
Voltage variations – steady state - feeders	3,000
Voltage variations – steady state – zone substations	248
Voltage variations – 1 minute	0
Voltage variations – 10 seconds	70

7.2.3 Asset utilisation

JEN considers the optimum utilisation on zone substation at this level to be between 66 per cent and 68 per cent. Accordingly, the proposed investment is designed to achieve network utilisation to within this reasonable risk level, as set out below.

Table 7-3: Utilisation targets for forthcoming regulatory control period

Utlisation performance measures	Target
Zone substation utilisation	66-68 %
Feeder utilisation (excluding stand-by feeders)	55-60 %
Number of feeders over 90 per cent utilisation	18

7.2.4 Customer service measures

The Electricity Distribution Code and the Public Lighting Code currently specify guaranteed service levels (**GSL**) which will be replaced by those included in the proposed STPIS. JEN proposes that these GSL payments will continue to relate to meeting customers' appointments on time, making supply connections and fixing public lights within specified time frames.

JEN's customer service measures include:

- appointments on time
- new connections on time
- repairing street lights on time
- customer complaints.

The tables below show the forecast number of payments for not meeting the customer service measure for the forthcoming regulatory control period. The figures do not take in to account services / complaints arising from the AMI rollout which will occur during the first three years of the regulatory control period.

Table 7-4: Customer service performance targets for forthcoming regulatory control period

Customer service performance measures	Target (number of payments pa)
Appointments on time	9
New connections on time	55
Street lights repair on time (within 2 business days)	41

Table 7-5: Customer complaints performance targets for forthcoming regulatory control period

Customer complaints performance measures	Target
Complaints – total per 1000 customers	1.8
Complaints – connection & augmentation	60
Complaints – reliability of supply	72
Complaints – technical quality of supply	168
Complaints – administrative process or customer service	48
Other complaints - distribution	192

7.2.5 *Safety indicators*

JEN is committed to providing a safe network and work environment for all employees and contractors. This commitment extends to taking all practical steps so that operations do not place the environment at risk or our community at risk of injury or illness.

It is important that the electricity network is operated and maintained so as to minimise the safety risk to members of the public as well as employees. Therefore, JEN's targets are:

- zero fatalities
- zero environmental infringements
- minimal public safety events.

7.2.6 *Asset condition indicators*

The indicator JEN uses to measure performance in this area is the number of feeder faults per 100 km of line due to equipment failure. This indicator has shown a gradually increasing trend of asset deterioration. The target for this measure is based on maintaining recent performance and is shown in Table 7-6.

Table 7-6: Asset condition indicators for forthcoming regulatory control period

Performance indicators	Target
Number of feeder faults per 100 km of line due to equipment failure	4.5

The remaining part of this chapter sets out how JEN has determined its capital and operating plan to achieve its targets.

7.3 JEN's network planning framework

JEN's forecast capex and opex is designed to enable JEN's network and IT to deliver an appropriate level of customer service in compliance with its regulatory obligations.

The NAMP and resulting COWP take account of:

- a detailed assessment of the impact of aging infrastructure on asset replacement requirements
- increased utilisation of network assets

- a number of new external drivers, such as the network impacts of climate change and heightened bushfire risks.

7.3.1 Network asset management plan (NAMP)

The NAMP is a key and central component of JEN's asset management process. It sets out the key strategies which JEN intends to pursue over the period 2009 to 2015 in order to meet its strategic objectives. In particular, the NAMP ensures that all investment decisions are justified on economic grounds, and that they consider:

- key asset management objectives relating to safety, compliance and sustainability
- the external operating environment and emerging issues such as climate change
- technological advancements such as smart grids
- the level of service required by network users
- forecast demand for network services
- options for non-network and demand side solutions
- a life-cycle approach to asset management balancing capex and opex requirements.

JEN has a proven and integrated asset management process, which identifies when assets need to be created, maintained, refurbished or replaced. The NAMP also establishes how JEN intends to build its asset base to deal with growth on the system, drawing from annual planning processes.

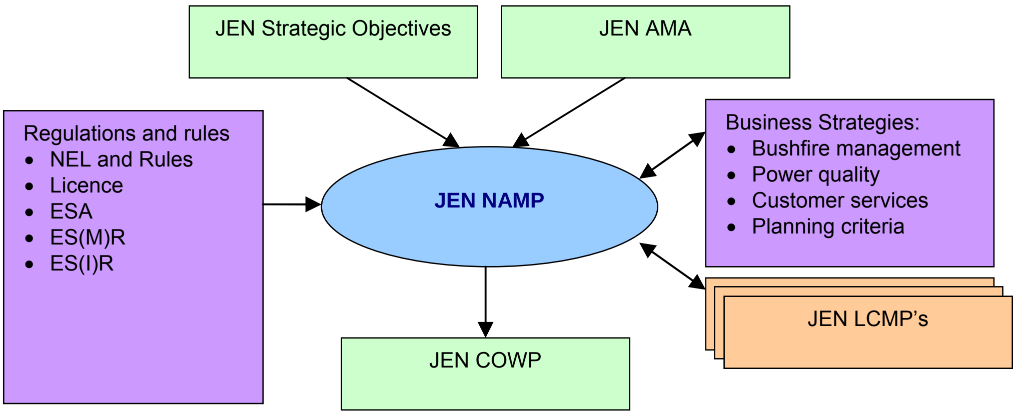
The NAMP covers all of JEN's key investment processes; in particular, identification and implementation of capex and opex projects and programs. The resulting expenditure forecasts are set out in chapters 8 and 9 of this regulatory proposal and in JEN's COWP.

7.3.2 Development of the NAMP

The key document informing the NAMP is JEN's Strategic Objectives Plan (Appendix 9.4) which encapsulates JEN's asset management policy, long term objectives, and performance and condition targets.

The NAMP is supported by, and draws together, other more detailed asset management plans as shown in Figure 7-2.

Figure 7-2: Development of the NAMP



At a high level, JEN's asset management strategy and process involve consideration of:

- existing asset utilisation and capacity to meet load growth
- the connection of new customers
- managing existing asset performance and condition
- strategies for asset maintenance, refurbishment and replacement
- managing network safety and environmental risks.

The development of JEN's NAMP is fully described in chapter 3 of the NAMP (Appendix 9.1).

7.3.3 Inputs to the NAMP

JEN maintains an extensive matrix of internal asset-related documents that collectively translate the company's understanding of its stakeholder requirements into action plans. These are updated annually or as required to reflect changing stakeholder requirements or other externalities. These documents include:

- asset lifecycle management strategies (maintenance and replacement)
- growth capital plan
- levels of service (network performance – reliability, power quality and customer service)
- standard policies and procedures

- engineering standards
- asset specific maintenance manuals
- management systems, quality (ISO9001), environmental (ISO14001) and safety (AS/NZS4801)
- bushfire mitigation plan
- vegetation plan
- risk management plan.

These plans are provided in Appendix 11 as support to the NAMP.

7.3.4 IT strategy and asset management plan (ITP)

JAM has prepared a comprehensive ITP for JEN over the forthcoming regulatory control period (provided at Appendix 9.2). The ITP sets out the IT capital and operating costs required to support JEN in achieving its strategic objectives.

The ITP aims to maintain and develop the IT environments to support JEN in providing electricity distribution network services. JEN faces a number of challenges as well as opportunities from internal and external perspectives to achieve its strategic intent. The challenges and opportunities include:

- increased focus on customer and market services
- increasingly high volume, scale, increased frequency and consequences of emergencies
- increased complexity in regulatory and statutory obligations
- substantial energy market operator improvement initiatives.

JAM developed the IT capital program by identifying the IT capability improvements required to support JEN's business capabilities. The program aims to take advantage of new technologies and capabilities to support JEN and to improve the efficiency and effectiveness of the network services through IT solutions.

All of JEN’s IT environments require lifecycle replacements and upgrades to maintain stability, promote technical performance efficiency and currency to avoid increases in maintenance and support costs due to aging. The environments also need to cater for organic growth and minor capability enhancements. These ongoing capital expenditures are an integral component of the IT capital program.

7.3.5 Network planning governance

Under the AMA, the NAMP and ITP are developed annually for JEN's approval. To assist in the development of the NAMP and ITP, JEN provides JAM with a strategic plan describing JEN's medium to long term objectives for the operation, maintenance, and development of its network and IT assets. The governance arrangements around the approval of the NAMP and ITP are set out in section 3.4 of the NAMP.

7.4 Key challenges addressed by the network asset management strategy, processes and plans

The key challenge addressed by JEN's network asset management strategy over the forthcoming regulatory control period, is to maintain reliability despite:

- aging assets
- increased network utilisation
- external factors, including:
  - the ongoing impacts of climate change
  - heightened bushfire risk/awareness
  - changes to the Electricity Safety Act, and national regulations
  - enhancing customer communication during extreme events in order to implement the recommendations from reports by the ESC and the OESC.

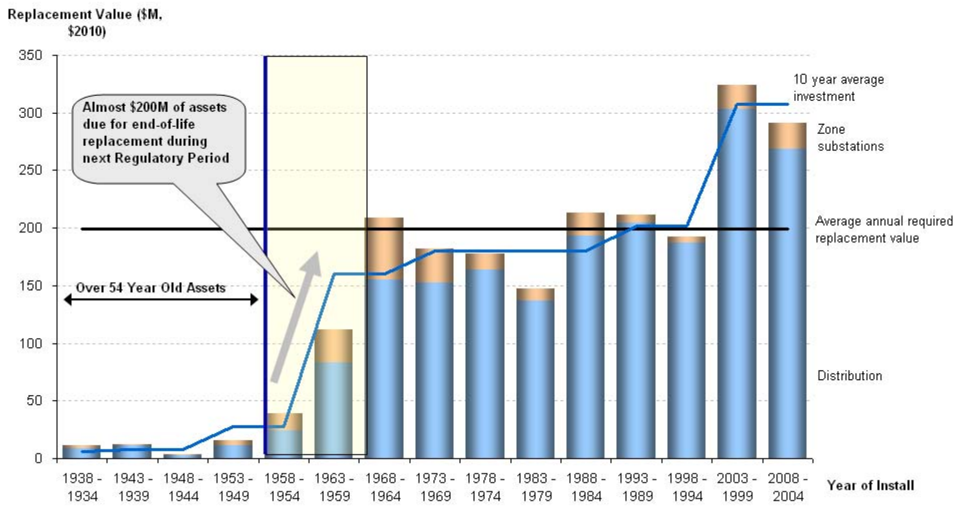
These are discussed below.

7.4.1 Managing aging infrastructure

Electricity distribution assets have long lives (typically 50 years) and many of the assets within the network have reached this age. The average remaining life of the network is 26.5 years (based on anticipated asset life). Over the past 10 years, assets have not been replaced at an adequate rate and this has resulted in a reduction in the average remaining life.

Figure 7-3 shows the general age of the network. A significant portion of the assets will be 50 years or older into the next five years. With the weighted average life of assets estimated at 50.3 years, a significant "bow wave" of asset replacement is forecast.

Figure 7-3: Asset replacement value by installation year – 5 year blocks



Recent ESC comparative performance reports indicate that JEN has a high proportion of supply interruptions caused by equipment failure relative to other Victorian distributors.[26] Equipment failures that result in customer outages on the JEN network have been growing. Should these trends remain unchecked, it is forecast to result in deterioration in reliability of between 1 and 2 minutes SAIDI per year.

The indicator used to measure performance in this area is the number of feeder faults per 100 km of line due to equipment failure.

JEN's performance against this asset condition indicator is in Table 7-7, which shows an increasing trend of asset deterioration.

Table 7-7: Asset condition indicator

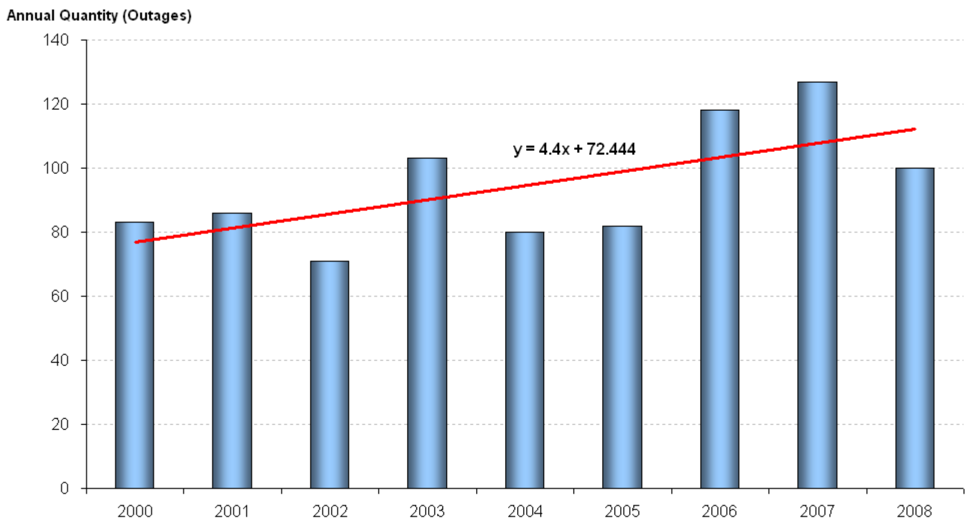
Performance indicator	2000	2001	2002	2003	2004	2005	2006	2007	2008
Number of feeder faults per 100 km of line due to equipment failure	3.4	2.5	2.4	4.5	3.2	3.3	4.4	4.5	4.6

The number of unplanned outages due to equipment failure is indicative of the overall condition of the network. While outages may be caused by external factors such as weather, bushfire, natural disasters and acts of god, the frequency is likely to increase if an area of the network ages to a point where it becomes more

[26] ESC, *Electricity distribution businesses: Comparative performance report 2007*, 2008, p. 25.

unreliable and is not subject to sufficient maintenance or replacement. Figure 7-4 shows the increasing trend in equipment failures.

Figure 7-4: High voltage equipment failures resulting in outages



JEN's NAMP focuses on activities that will arrest this trend as more assets move into their end-of-life phase. This approach will ensure that JEN can meet its regulated reliability targets in the future and enable JEN to manage public health and safety risks associated with asset failure.

Previous owners of JEN's network managed reliability in part through deferring asset replacements by extending the life of assets. Many of these effective asset-life extension programs that were implemented in the 1980s have now matured—for example: pole preserving, pole staking, condition monitoring, with little opportunity for further life extension. In the meantime, the deferral of asset replacement has absorbed available contingencies in managing the network.

JEN's asset management strategy for the forthcoming regulatory control period is to increase replacement of end-of-life network assets in line with good industry practice and JEN's regulatory obligations. This approach will address the under spend in replacement capex that has occurred in previous regulatory periods:

- during the period 2001-2005, JEN's asset replacement expenditure was equivalent to replacing network assets with an average 130 year network life

- during the current regulatory control period, the asset replacement expenditure has increased and is equivalent to replacing network assets with an average 80 year network life.

During the forthcoming regulatory control period, JEN's proposed asset replacement expenditure will further increase and is equivalent to replacing the network assets based on an average 53-year network life. This expenditure level is considerably closer to the average expected life of network assets.

7.4.2 Managing asset utilisation

A consistently high utilisation of the network is important to ensure that proposed investments do not result in customers bearing increased costs. Careful attention to planning and design of the network is required.

NIEIR has forecast that summer peak demand will continue to grow at an average of 2.1 per cent in the forthcoming regulatory control period, due to the continued penetration of domestic air conditioning loads. The growing peak demand will require significant network augmentation.

The 2009 heat wave has uncovered air conditioning loads through localised overloads in the low voltage distribution network. The processes to forecast local overloads of distribution substations using the substation utilisation profiling system has since been improved to reduce overload failures and enables better targeting of localised demand related capital expenditure.

Increasing customer electricity demand will drive significant investment in network augmentation. JEN's network investment expenditure has been increasing at a lower rate compared with electricity demand growth so spare network capacity has been gradually used up to meet growing demand. This investment growth cannot continue at the current rate into the future without affecting the security of supply to customers.

The utilisation of zone substations has been steadily increasing since 2002 with current utilisation being 13 per cent higher than in 2002. The average utilisation of JEN's zone substations was 68.7 per cent in 2009. Similarly the utilisation of high-voltage feeders has also increased, albeit at a lower rate with utilisation being 8 per cent higher over the same period. This indicates that spare network capacity has been used up to meet growing demand. However, this cannot continue at the same rate into the future without affecting the security of supply to customers.

JEN considers the optimum utilisation at this level of the network to be between 66 and 68 per cent. The proposed investment of new zone substations and subtransmission lines over the forthcoming regulatory control period will restore the network utilisation to within these reasonable risk levels.

For the population of approximately 5,500 distribution substations, approximately 20 per cent are overloaded (loaded above 100 per cent of their cyclic rating).

JEN's COWP includes funding of $60 million to increase local capacity at the distribution substation asset level. Significant localised overload of this asset class resulted in customer supply interruptions during last summer's heat wave, with the overload predominantly caused by the increase in domestic air conditioning. JEN has commenced an investment program to increase the capacity of distribution substations, with the program to continue into the planning period to address the emerging capacity constraints.

7.4.3 Climate change

As outlined in section 2.8.1, climate change is evident from recent events experienced in Victoria including extreme heat-waves, unprecedented drought, stronger storms and more intense bushfires.

JEN's network strategy aims to manage and adapt the network to these changing conditions, while still achieving the reliability and quality of services required by customers.

In 2009 JEN engaged AECOM to report on the likely climate scenario for the forthcoming regulatory control period, and the material impacts of such climate conditions on the performance, asset conditions and capability of JEN's network. The project brought together expertise in climate science, risk management, electrical engineering, asset management and climate change adaptation. It has synthesised the respective opinions and advice to inform a reasonable adaptation and management response.

AECOM's report[27] provides a number of findings and recommendations for JEN regarding the impact of climate change on its business. The report states:

"…for networks and businesses, it is no longer 'prudent' to manage future network performance on the basis of past climatic conditions. [Electricity distribution businesses'] business as usual approach to managing and maintaining electricity supply is in many areas no longer sufficient to maintain network performance under changing climatic conditions. The expected increase in extreme climatic events is likely to exacerbate the pressure on most [electricity distribution businesses'] networks."

Over the forthcoming regulatory control period JEN expects climate change to increase its:

- asset replacement requirements due to external damage to, and aging of assets
- peak demand resulting in increased reinforcement investment requirements
- network total SAIDI in the order of 13.9 minutes per year before exclusion.

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[27] AECOM, *Assessment of Climate Change Impacts on Jemena Electricity Networks for 2011-2015 EDPR*, September 2009.

This is discussed further in section 4.3 of the NAMP.

7.4.4 Bushfire management

The purpose of the bushfire mitigation policy is to minimise the risk of fires caused by network assets and to ensure compliance with legislative and regulatory requirements. Climate change projections have highlighted the increase in bushfire risks due to the continued drought and high temperatures.

JEN's NAMP includes a number of initiatives to reduce the risk of fire starts by electricity assets. The risk of fire starts has increased significantly due to the prolonged drought which is forecast to continue due to climate change. Initiatives include the retirement of single wire earth return (**SWER**) system, fault current reduction by the installation of resonant earthing at three zone substations, and increased vegetation management.

This is discussed further in section 4.5 of the NAMP.

7.4.5 National changes to regulations

As noted in section 3.2.3, the Electricity Safety Act (1998) will shortly be changed. As a result, from 1 January 2010, JEN must develop and maintain an ESMS or safety case. This will result in additional resources and increased costs to develop the ESMS and associated programs, and to audit performance.

Also, on 1 July 2009, new Environment Protection (Industrial Waste Resource) Regulations 2009 came into operation, which effectively require a shift of risk from the EPA to JEN. JEN needs to dispose of the waste generated by its operations. Recent changes by the EPA have increased the costs of disposal to reach the objective of zero hazardous waste to landfill by 2020.

8 Forecast capital expenditure

This chapter provides JEN's forecast capital expenditure and explains how this regulatory proposal complies with the capital expenditure objectives, criteria and factors specified in the Rules. It sets out the key assumptions that support JEN's forecast capital expenditure for the forthcoming regulatory control period and demonstrates compliance with RIN clause 3 and Rules clause 6.5.7 and schedule s 6.1.1.

This chapter is structured as follows:

- *Summary* – provides an overview of JEN's proposed forecast capex requirements over the forthcoming regulatory control period

- *Elements of JEN's capital program* – outlines how JEN incurs capital and the resulting ways in which JEN's forecast capex is defined and how JEN has allocated these into the categories prescribed by the AER's RIN

- *Context* – explains the aims and objectives, and documents relied upon by JEN in developing its capex forecasts

- *Capex forecasting process* – explains how JEN has developed its capex forecasts including the key assumptions and description of how JEN has relied upon its business policies, practices and processes and its detailed network asset management plan and IT plan to develop its capex forecast

- *Key assumptions* – sets out the key assumptions underpinning JEN's capex forecasts

- *Forecast capex by cost category* – sets out the JEN forecast capex in the cost categorisations required by the AER's RIN

- *Consistency with capex criteria, factors and objectives* – demonstrates how JEN's capex forecasts comply with the capex criteria, factors and objectives set out in the Rules

- *Other Rule considerations* – provides JEN's required explanation of the interaction between capex and opex forecasts, consideration of the reliability targets, the delineation of fixed and variable components and independent validation of the way JEN has reflected demand growth in its capex forecasts, compliance with the CAM, material projects.

8.1 Summary

JEN’s total forecast capex requirement over the forthcoming regulatory control period for standard control services is $669.2 million, including customer contributions.

Key outcomes of JEN’s forecast capex are:

- delivery of four new zone substations located at key load centres; the installation of nine power transformers to augment existing zone substations; replacement of 2,500 poles and 18,800 pole tops to ensure the performance and condition of the assets is maintained at acceptable standards; the construction of new distribution feeders and considerable re-arrangement and upgrade of existing feeders; the connection of 22,919 new residential customers and 2,199 new larger customers; and the consolidation of critical depots to improve operational efficiencies

- there are 290 separate projects or programs of capital works that incur expenditure over the forthcoming regulatory control period; 22 of these exceed the network related material project threshold of $5 million, while 8 exceed the non-network related threshold of $2 million

- the capex forecast is a current day estimate and reflects views on various underlying investment drivers and JEN’s need to comply with its obligations as a distribution network service provider (see chapter 3)

- the capex forecast process has involved a detailed bottom-up review of projects and programs across various categories based on long standing and well defined business policies, strategies and asset management practices as detailed in JEN’s business systems and documents

- at a high level, the forecast capex is considered prudent as a clear need has been established at a project and program level consistent with the business and regulatory objectives and obligations, including a risk-based probabilistic planning approach, a robust economic assessment of technical options to mitigate risks, condition and performance based knowledge and assessment of existing plant and a refined capex governance framework

- at a high level, the cost of undertaking the work is considered efficient given the integrated and optimised processes used by JEN to develop the investment forecasts, including a refined capex governance framework, and sound procurement practices coupled with well established design and construction standards

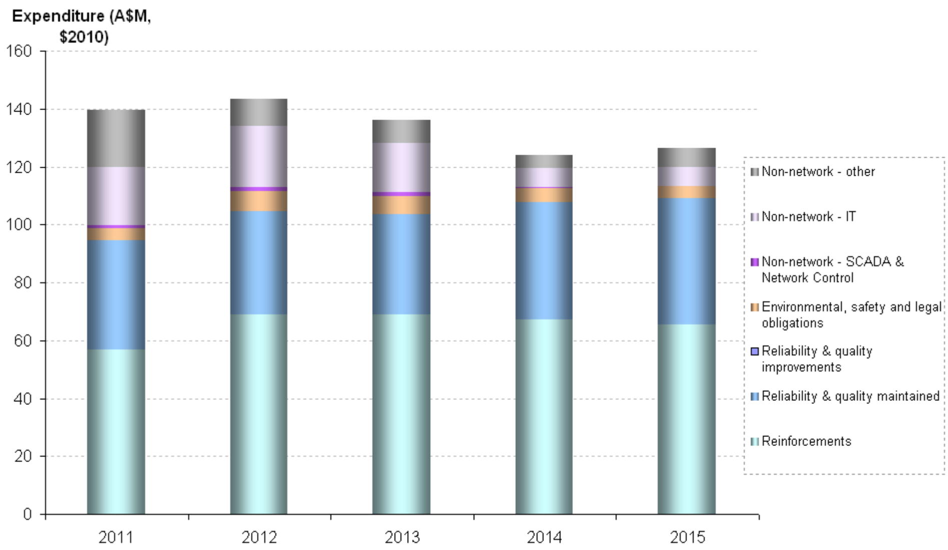
- forecasts have been reviewed by external experts to assess their compliance with the relevant Rules provisions and to benchmark the costs against those of other networks.

JEN's annual forecast capex for regulated standard control services (including customer contributions), as categorised into key regulatory categories is shown in Table 8-1 and Figure 8-1 shows that the key areas of capital investment for JEN are associated with the typical electricity distribution network functions of capacity related reinforcements, maintaining reliability and quality standards, and connecting new customers.

Table 8-1: Forecast capital expenditure over the forthcoming regulatory control period

Details, 2010 $M	2011	2012	2013	2014	2015	Total
Reinforcements	56.7	68.9	68.7	67.2	65.5	327.1
Reliability & quality maintained	38.0	35.9	34.9	40.5	43.5	192.7
Reliability & quality improvements	0.0	0.0	0.0	0.0	0.0	0.0
Environmental, safety and legal obligations	4.1	6.9	6.2	4.6	4.1	26.0
SCADA & Network Control	0.8	1.2	1.2	0.3	0.0	3.6
Total network	**99.6**	**112.9**	**111.0**	**112.7**	**113.2**	**549.4**
Non-network – IT	20.2	21.1	17.2	6.6	6.8	71.9
Non-network - other	19.8	9.4	7.8	4.6	6.3	47.9
Total non-network	40.0	30.5	25.0	11.2	13.1	119.8
Total forecast capex	**139.6**	**143.4**	**136.0**	**123.9**	**126.3**	**669.2**

Figure 8-1: Forecast capital expenditure over the forthcoming regulatory control period



Further details of JEN's forecast capex at a categorised project and program level are contained within the COWP, including its detailed appendices.

8.2 Elements of JEN's capital program

As discussed in Chapter 7, JEN's approach to managing its network assets is focussed on achieving defined functional objectives and targets and responding to drivers at various levels of the network. The systems and processes embedded in the business to support robust decision-making and controls are based on different capital expenditure categories to those adopted in regulatory accounts or specified in the AER's RIN. Table 8-2 indicates how JEN's capital expenditure categories map to the categories prescribed in the RIN.

Table 8-2: Capital expenditure categories

RIN capital expenditure category	JEN capital expenditure category
Reinforcement	Network initiated augmentation and performance
Reliability and quality maintained	Asset replacement Network initiated augmentation and performance
Environmental, safety and legal	Asset replacement Network initiated augmentation and performance
New customer connections	Customer initiated connections

RIN capital expenditure category	JEN capital expenditure category
Non-network - other	Non-network
Non-network IT	IT
Non-network – SCADA and Network control	Non-network

JEN notes that it has:

- been developing and providing regulatory categorisations of capital expenditure information based on its internal categories within reports to the ESC since 2000
- no forecast capex over the forthcoming regulatory period associated with the RIN categories of improved reliability and quality at a system wide level, or with load movement.

8.2.1 Allocating to prescribed capex categories

Table 8-3 provides the definitions used by JEN to differentiate between each capex category. JEN provides this information in accordance with RIN clause 3.1(a)(ii). In so doing, JEN notes that when translating its capex at a project and program level into the RIN defined categories, JEN has adopted a pragmatic approach based on its view of the primary investment driver.

Numerous projects provide benefits that are spread across the defined categories – for example the replacement of an asset in poor condition and presenting relative poor performance is likely to ensure locational reliability standards are maintained, increased capacity given the use of modern equivalents, whilst also ensuring compliance with an environmental or safety standard. JEN has generally used the primary trigger or need for each investment, as informed by the process used to identify the investment, to allocate it to the RIN capex categories.

Table 8-3: Capital expenditure categories and descriptions

Capital expenditure category	Description
JEN category	
Network initiated augmentation and performance	This includes a broad range of projects and programs of work that have been identified through JEN's annual planning review process, and which focus on the capacity and utilisation of assets and their ability to meet growth in demand and the performance of the integrated network. Typical investment includes new and upgraded zone substations and feeders, works to manage fault levels and to deliver communication, protection and control requirements

Capital expenditure category	Description
Asset replacement	This includes a range of investments targeted at asset classes, which are informed through the ongoing life-cycle based asset management processes, including the analysis of the condition and performance of assets gathered through regular defect inspection and maintenance activities. Typical investment includes replacement of poles and pole top equipment across the network as well as within zone substations, such as circuit breakers and transformers
Customer initiated connections	This includes projects required to connect new customers seeking access to the distribution network and is informed through historical experience providing this service and anticipated customer numbers. Customer types vary from dual and multiple residential occupancy to larger industrial customers, including special capital works. Importantly, the forecasts presented by JEN include the amount that will be recoverable through the application of its published customer contribution policy
Non-network	This comprises works associated with providing and supporting regulated business services in the form of SCADA and network control equipment, other tools and equipment, buildings, property vehicle and heavy machinery
RIN category	
Reinforcement	This RIN category includes a subset of JEN's network initiated augmentation and performance capex, that is solely associated with load-growth related increases in capacity
Reliability and quality maintained	This is a RIN category that includes a combination of both asset replacement and network initiated augmentation and performance capex, and is primarily associated with maintaining existing levels of reliability and quality of supply to customers. The vast majority of this category is associated with asset replacement investment
Environmental, safety and legal	This is also a RIN category that includes a combination of both asset replacement and network initiated augmentation and performance capex, and is primarily associated with ensuring compliance with existing and new environmental, safety and legal obligations contained within various instruments. Typical projects include managing risks with overhead services, improving building security and lighting and installing ground fault neutralisers
New customer connections	This is a RIN category that is in direct alignment to JEN's customer initiated capex category

Capital expenditure category	Description
Non-network other	This is a RIN category that disaggregates JEN's non-network capex into everything other than SCADA and network control capex
Non-network – SCADA and Network control	This is a RIN category that disaggregates JEN's non-network capex into SCADA and network control capex only
Non-network IT	This category comprises IT system implementations, upgrades, replacements, organic growth and enhancements designed to facilitate delivery of network services.

8.3 Context

JEN has had regard to the capital expenditure objectives under Rule 6.5.7(a) when establishing its capex forecast. The capex forecast has also been informed by the:

- JEN strategic objectives provided in Appendix 9.4
- the NAMP and COWP provided in Appendix 9.1 and 10
- JEN's life-cycle management plans in Appendix 11
- the AMA between JEN and JAM in Appendix 17
- expert reports influencing forecasting JEN's assumptions that JEN obtained from NIEIR, BIS Shrapnel, SKM, Evans & Peck, and AECOM provided in Appendix 7
- expert reports reviewing the compliance of JEN's capital programs for its IT systems and network with the relevant provisions of the Rules obtained from Ernst & Young and GHD respectively provided in Appendix 7.6 and 7.7 respectively.

In addition to these key inputs, JEN's capex forecasts also reflect the various internal business policies and procedures set out in RIN template 6.4.

In developing its capex forecasts JEN has also had regard to its:

- service obligations set out in section 3.2
- service performance targets set out in section 7.2
- safety and operating regulations and obligations set out in section 3.2.

JEN has prepared its capex forecast in accordance with its proposed CAM. A copy of this CAM is provided in Appendix 8.

JEN's capex forecast relates to all distribution services falling under standard control services.

JEN's network planning and augmentation obligations are currently regulated by the ESC under the Victorian Electricity Distribution Code. The annual planning requirements in the Code do not require JEN to apply the regulatory test. Accordingly, no capital expenditure is identified for the purposes of clause 6.5.7(b)(4) of the Rules.

8.4 Capex forecasting process

JEN has leveraged off its existing internal asset management processes as described within its NAMP (and its numerous supporting documents) in order to develop its overall forecast capex proposal. In particular, this includes:

- the annual planning review accounting for detailed technical analysis of the capability and configuration of the existing assets to meet forecast demand culminating in the publication of an annual Distribution System Planning Report
- the need to connect new customers
- the ongoing monitoring and analysis of the condition and performance of the assets through asset lifecycle planning
- the rationalisation and optimisation of both capex and opex through annual budgeting processes and individual asset lifecycle management plans.

Specifically, the process has involved a detailed bottom-up assessment at a project and program[28] level across various expenditure categories, which has accounted for JENs considerations of:

- external drivers influencing the expenditure categories and provision of network services, such as peak demand, energy consumption growth and new customer connections
- historical investment levels
- service levels and stakeholder and customer expectations
- various asset management strategies and whole-of-life implications

[28] JEN has defined project to mean a series of related works with a defined start and end date. A program is defined to mean an ongoing series of works.

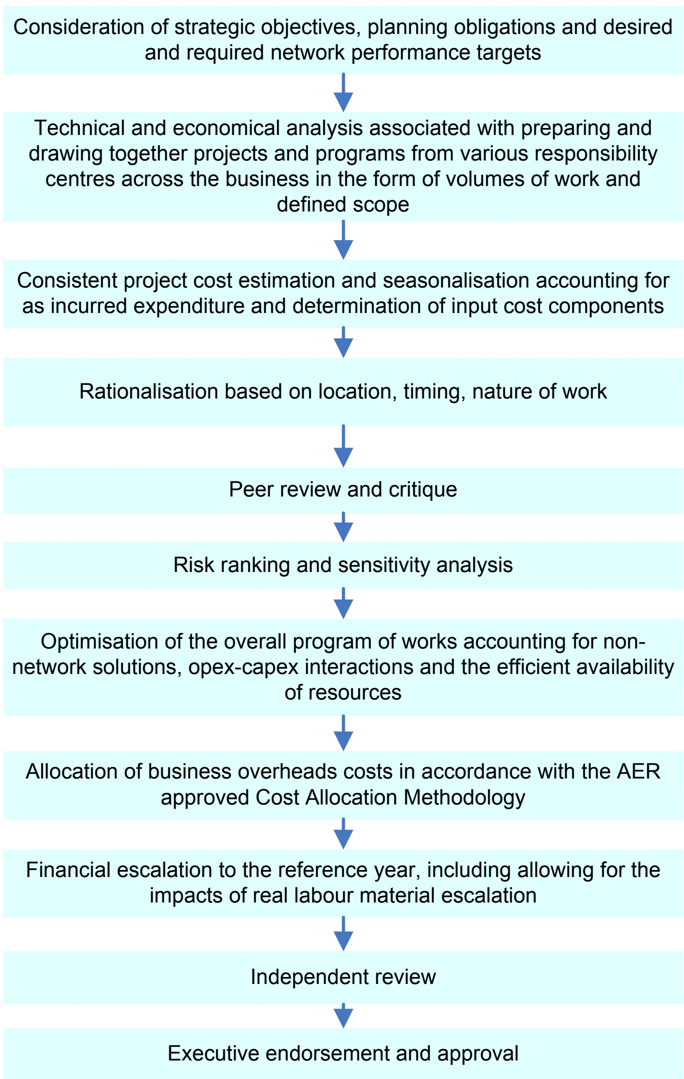
- regulatory, environmental, safety and legal obligations established through license conditions, in particular in the context of the extensive physical coverage of JEN's assets

- the balance between costs and benefits in the context of various technical and regulatory risks given the underlying need and timing of investment

- the overall procurement, design standards and deliverability of the program of works.

JEN has illustrated these considerations and their chronology in Figure 8-2.

Figure 8-2: Capex forecasting process



Notwithstanding the difficulty in forecasting across such an extensive planning horizon, JEN considers the forecasting process adopted is appropriate because:

- it has been based on detailed technical and engineering knowledge of the condition, performance and utilisation of the assets gained through years of investment, monitoring, analysis and observation
- it is expected to deliver a level of service consistent with stakeholder and customer expectations, whilst maintaining reliability standards at existing levels
- it has been based on existing business processes and systems used to inform annual budgeting decisions
- it is readily transparent and leverages off integrated asset management practices, objectives and strategies
- JEN has sought and depended on independent review and advice for validation
- it has been undertaken in a controlled, well considered and co-ordinated manner with a direct view to the capital expenditure objectives defined in the Rules.

Further, JEN has relied on fit-for-purpose forecasting methods when considering each capex category. These are detailed in JEN's COWP and ITP.

8.5 Key assumptions

Table 8-4 sets out the key and other assumptions used by JEN to develop its forecast capex.

Table 8-4: Key and other assumptions underpinning forecast capex

Program	Relevant key assumptions	Further relevant assumptions
Reinforcement	NIEIR peak demand and customer number forecasts BIS Shrapnel labour forecasts SKM input materials forecasts	Planning standards and VCR are maintained at existing levels. VCR from VENCorp study[29]. Failure rates and probabilities of outages are consistent with historical experience and models adopted

[29] CRA, *Assessment of the Value of Customer Reliability*, August 2008

Program	Relevant key assumptions	Further relevant assumptions
Reliability and quality maintained	Current five year rolling average performance indicators under the STPIS AECOM climate change expectations BIS Shrapnel labour forecasts SKM input materials forecasts	Condition and age of assets is accurate within business systems Jurisdictional service standards are maintained Technical quality of supply standards are maintained No additional, critical technical risks or failure modes emerge that have not been considered
Environmental, safety and legal	BIS Shrapnel labour forecasts SKM input materials forecasts	Regulatory and legislative obligations, except where noted, are maintained Bushfire management obligations are maintained Implementation of the mandatory electricity safety management scheme
New customer connections	NIEIR residential customer number forecasts BIS Shrapnel labour forecasts SKM input materials forecasts	Unit rate forecasts for each activity based on historical rates Historical expenditure and volumes are representative Construction Forecasting Council expenditure forecasts Existing customer contribution policy is maintained Major new customer loads that are confirmed over the next seven years are also included in the forecast
Non-network - other	BIS Shrapnel labour forecasts SKM input materials forecasts	Fleet replacements based on time-based replacements of line construction trucks, tipper trucks heavy commercial vehicles, light commercial vehicles and passenger vehicles as modified by condition and mileage Condition and age of assets is accurate within business systems
Non-network – SCADA and network control	BIS Shrapnel labour forecasts SKM input materials forecasts	Condition and age of assets is accurate within business systems

Program	Relevant key assumptions	Further relevant assumptions
IT systems	NIEIR customer number forecasts BIS Shrapnel labour forecasts	

Accounting for demand

Where appropriate, JAM's capex forecasting methods are informed by the NIEIR forecasts of peak demand, customer numbers and energy consumption. The areas where JAM has had regard to demand and the nature of the forecasting relationship are detailed in the COWP and ITP.

The major projects that these forecasting methods have identified as required to address peak demand within JEN's network are:

Commercial in Confidence

- major network reinforcement in Airport West/Tullamarine, Broadmeadows, Somerton/ Craigieburn, Sydenham/ Sunbury areas to meet future demand
- continuation of Preston and East Preston Conversion Program, from 6.6 kV to 22 kV
- review and update management processes for distribution substations and LV network (including augmentation program) to maintain network performance.

Accounting for climate change

JEN has had regard to the climate change effects identified by AECOM when developing the capital program to ensure reliability maintenance.

Accounting for input cost escalation

Unit costs reflect historical experience, including competitive tendering, benchmark prices and independent quotes and offers, and assuming that current design and engineering standards are maintained.

JAM initially forecast all capex costs in 2009 dollars, and then adjusted them for the real input cost escalators determined by BIS Shrapnel and SKM, in accordance with instructions from JEN. JEN's escalators are described in section 9.3 and are detailed in Appendices 7.1 and 7.2.

Commercial in Confidence

8.6 Forecast capex

The application of JEN's capex forecasting method provides a five year capex proposal of $669.2 million for the forthcoming regulatory control period. During the current regulatory control period JEN expects the total capex to be $372.6 million, based on three years of actual expenditure and estimates for the last two years of the period. The proposed capex for the forthcoming regulatory control period therefore represents a 79.6 per cent increase in real terms over the current regulatory control period.

The aggregated forecast capex can be presented in a number of different ways, specifically it can be categorised by:

- RIN regulatory categories (i.e. reinforcements, reliability and quality maintained, etc)
- JEN's functional expenditure categories (i.e. asset replacement, network initiated demand and performance, etc)
- asset class (i.e. types of feeders, zone substation plant, etc)
- input cost components (i.e. material, labour, etc).

Table 8-1 presents the forecast capex by RIN regulatory categories. JEN notes that it has no capex relating to reliability and quality improvements or load movement.

Table 8-5 provides these capex forecasts within the categories that reflect JEN's functional (and forecasting) basis.

Figure 8-3 shows the long term trend in investment across the current and forthcoming regulatory control period, indicating the increasing trend in capex investment peaking in 2012, and then tapering off towards the end of the outlook period.

Figure 8-3: Capex forecast and historic investment context (net of customer contributions but including public lighting)

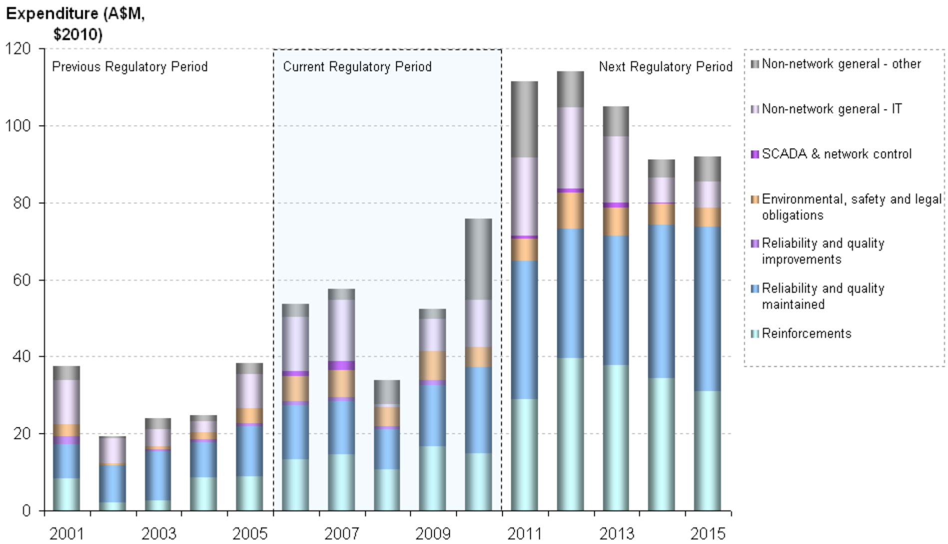


Table 8-5 presents the forecast capex solely according to JEN's functional expenditure categories.

Table 8-5: Forecast capital expenditure over the forthcoming regulatory control period

Details, 2010 $m	2011	2012	2013	2014	2015	Total	Per cent of total
Asset Replacement	30.5	30.9	32.0	37.1	39.7	170.3	25%
Customer Initiated	28.1	29.3	31.1	32.8	34.5	155.8	23%
Network Initiated (Demand & Performance)	40.1	51.5	46.7	42.5	38.9	219.7	33%
Non-network	40.8	31.7	26.2	11.5	13.1	123.4	18%
Total forecast capital expenditure	139.6	143.4	136.0	123.9	126.3	669.2	100%

Further details on the forecast capex can be obtained within JEN's RIN templates, where the expenditure is presented in terms of defined asset class categories and input cost components.

8.7 Consistency with capex criteria, factors and objectives

JEN has considered whether its planning and forecasting processes are consistent with the capital expenditure objectives and capital expenditure criteria and address the capital expenditure factors specified in the Rules, and whether the resultant forecasts met these requirements.

JEN concluded that its planning processes explicitly considered the drivers of expenditure set out in the capital expenditure objectives and that its analysis and governance processes address the matters raised in the criteria.

In relation to the resultant expenditure forecasts, JEN believes that the forecast capital program is consistent with requirements of the Rules and that the associated costs are efficient and prudent.

8.7.1 Capital expenditure objectives

JEN has established its capex forecasts to comply with the capital expenditure objectives specified in the Rules. JEN has primarily achieved this by:

- examining the condition and age of its network assets
- assessing the sufficiency of its current compliance with regulatory obligations to identify required investments for corrective actions in a steady state
- assessing foreseeable changes in the network operating environment such as expert views of climate change effects and the additional network performance information available through AMI to identify any additional investments required to maintain reliability
- identifying any new or changed obligations that will affect its network capital program
- quantifying customer initiated capital requirements as informed by independent expert demand forecasts
- incorporating escalation for expert determined input cost escalation.

Table 8-6 summarises how JEN has complied with the operating expenditure objectives.

Table 8-6: Capital expenditure objectives

Operating expenditure objective	Rule	JEN actions to ensure compliance
Meet or manage the expected demand for standard control services	6.5.7(a)(1)	JEN has forecast its relevant capital categories to take into account the growth effects of expert determined peak demand, customer number and consumption forecasts.
Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services	6.5.7(a)(2)	JEN has assessed its current compliance as well as assessing corrective actions and additional new obligations
Maintain the quality, reliability and security of supply of standard control services	6.5.7(a)(3)	JEN has prepared a comprehensive COWP and NAMP with associated expenditure forecasts considering the impacts of climate change, ageing infrastructure and increasing utilisation on the quality, reliability and security of supply. The additional impact of the power quality information to be made available from AMI has also been factored into the COWP and the NAMP
Maintain the reliability, safety and security of a distribution system through the standard control services	6.5.7(a)(4)	JEN has prepared a comprehensive COWP and NAMP with associated expenditure forecasts considering the impacts of climate change, ageing infrastructure and increasing utilisation on the reliability, safety and security of supply. Additional considerations, including trends of asset failures and customer reports of safety issues as they impact potential future network safety issues, have also been factored into the COWP and the NAMP

8.7.2 Capital expenditure criteria

Future costs are efficient due to prudent commercial outsourcing

JEN has in-house functions to manage its costs and its outsourcing of asset management activities. Through this model, and in accordance with a formal commercial process, JEN has negotiated an asset management agreement with JAM that reflects JEN's interests in containing its costs and in ensuring that JAM provides a level of service that reflects good industry practice.

Further, JEN has secured contractual incentive arrangements that align JAM's incentives with those of JEN as regards both cost and service performance. These arrangements represent those of a prudent operator. Together with the use of independent expert cost driver inputs, they enable the AER to infer that JEN's costs over the forthcoming regulatory control period represent the efficient costs of a prudent operator in JEN's circumstances.

Independent verification of capital program prudence for network and non-network capital

JEN has obtained independent expert reviews of its proposed capital programs. Section 8.8.4 sets out the nature and outcomes of these reviews which concluded that JEN's capex, with one minor IT exception, is compliant with the prudence and efficiency capital expenditure criteria of the Rules.

Forecast methods reflect realistic expectations of demand and input costs

JEN has relied upon suitably qualified experts to inform its capital program costs including:

- NIEIR for demand
- SKM and BIS Shrapnel for estimates of cost escalators
- AECOM for climate change effects on the network and its performance.

8.7.3 Capital expenditure factors

The Rules set out the capital expenditure factors which the AER must have regard to when deciding whether or not to approve JEN's capex forecast. Table 8-7 summarises points JEN considers relevant to these factors.

Table 8-7: Capital expenditure factors

Capital expenditure factors	Rule	JEN comments
the information included in or accompanying the building block proposal	6.5.7(e)(1)	JEN has provided a comprehensive regulatory proposal supported by extensive appendices, financial models and RIN templates.
submissions received in the course of consulting on the building block proposal	6.5.7(e)(2)	
analysis undertaken by or for the AER and published before the distribution determination is made in its final form	6.5.7(e)(3)	
benchmark capital expenditure that would be incurred by an efficient Distribution Network Service Provider over the regulatory control period	6.5.7(e)(4)	JEN has provided independent benchmarking analysis from GHD and Ernst & Young in Appendices 7.6 and 7.7.
the actual and expected capital expenditure of the *Distribution Network Service Provider* during any preceding *regulatory control periods*;	6.5.7(e)(5)	JEN has provided its actual historic expenditure in chapter 5 and in RIN templates 5.1 and 5.2 (among others).
the relative prices of operating and capital inputs	6.5.7(e)(6)	JEN relies on lifecycle management planning for each asset, which considers all strategies and options over the entire asset life from planning to disposal to deliver the lowest long-term cost to deliver the organisation's strategic goals. Lifecycle management focuses on ensuring effectiveness and efficiency in maintenance (opex) and replacement (capex) of the network assets based on reliability centred maintenance analysis and considers issues of safety, cost, risk and reliability. Additionally, JEN has relied upon the same input cost escalators for capex and opex.

Capital expenditure factors	Rule	JEN comments
the substitution possibilities between operating and capital expenditure	6.5.7(e)(7)	JEN has assessed these opportunities and has proposed: • an enhanced asset inspection program (opex) to complement the asset replacement strategy (capex) • several IT capex projects that provide for corresponding savings in IT opex costs over the forecast period.
whether the total labour costs included in the capital and operating expenditure forecasts for the regulatory control period are consistent with the incentives provided by the applicable service target performance incentive scheme in respect of the regulatory control period	6.5.7(e)(8)	All significant proposals to commit funds are subject to an economic evaluation. All realistic options are included in the analysis. All costs, savings (both capital and operation/maintenance) and revenues relevant to each option are included in evaluations. These revenues include an assessment of the impact of the STPIS.
the extent the forecast of required capital expenditure of the *Distribution Network Service Provider* is referable to arrangements with a person other than the provider that, in the opinion of the *AER*, do not reflect arm's length terms	6.5.7(e)(9)	As discussed in Appendix 17.1 and demonstrated by the AMA, JEN has established outsourcing arrangements that reflect prudent commercial terms

Capital expenditure factors	Rule	JEN comments
the extent the *Distribution Network Service Provider* has considered, and made provision for, efficient non-network alternatives	6.5.7(e)(10)	JEN's base costs include costs for avoided network costs paid to the Somerton distributed generator. JEN proposes to continue these network support arrangements. There are seven embedded generators inter-connected to the network – Somerton Power Station in Somerton, Brooklyn Landfill in Brooklyn, Bolinda Landfill in Broadmeadows, Austin Hospital in Heidelberg, LaTrobe University in Preston, Mini Hydro in Preston and Australian Paper in Fairfield. Opportunities for non-network solutions are published in annual planning reports and proponents are invited to contact JEN for further discussions. These documents are published in order to provide transparency and information to the wider energy industry, with a specific objective of seeking opportunity for non-network solutions to defer the need for network investment.

8.8 Other Rule considerations

8.8.1 Reliability targets

JEN has assessed the adequacy of its current network assets and their condition to meet the proposed reliability targets set out section 7.2. This assessment included considering:

- expert advice from AECOM about the effects of climate change on JEN's service performance
- the implications of the improved customer site service performance information that will become available through the roll out of smart meters during the forthcoming regulatory control period for the measurement of reliability performance and JEN's consequent ability to meet the proposed targets
- expert determined peak demand forecasts at the terminal station level to assess likely network constraints.

Having regard to all these factors, JEN and JAM have developed a comprehensive schedule of reliability maintenance investments and prudent asset replacements to ensure that JEN is able to achieve the service performance targets. Key projects and programs contributing to the maintenance of JEN's current reliability performance are:

- as a result of increased asset failures, increasing expenditures are necessary on asset replacement to constrain the declining reliability performance to offset age degradation for assets such as pole top structures, underground cables and overhead conductors
- JEN is proposing to increase capex expenditure to reinforce the local distribution system. Significant additional capex is required to provide the required capacity especially under extreme heat wave conditions.

8.8.2 Deliverability of proposed capex and opex program

JEN's forecast capex for the forthcoming regulatory control period is significantly higher than the capital expenditure allowance for the current regulatory control period. JEN believes that it has or can acquire the systems, information and resources to deliver the network programs and projects over the forthcoming regulatory control period.

In forming its view on deliverability, JEN has had regard to the following:

- NAMP provided in Appendix 9.1
- COWP provided in Appendix 9.10
- ITP provided in Appendix 9.2
- GHD's review of the NAMP provided in Appendix 7.7
- Ernst & Young's review of the ITP provided in Appendix 7.6
- The AMA terms provided in Appendix 17.2.

JEN can deliver the higher capital program proposed for the forthcoming regulatory control period and it has implemented or commenced implementation of a range of initiatives to ensure that the increased challenging capital program can be delivered. These initiatives are discussed below.

Materials

As JEN's asset management provider, JAM has a number of long term contracts to ensure that materials are purchased in a timely and efficient manner to ensure the deliverability of the JEN program of work.

Outsourced service contracts

As JEN's asset management provider, JAM has partnered with other providers to supplement its internal workforce for delivery of works programs to JEN. Generally, these contracts are awarded following a competitive tendering process.

The outsourced contracts provide JAM with the flexibility to increase and decrease its requirements based on its work program. They also provide JEN access to a larger and more flexible workforce than it could prudently maintain on a standalone basis.

Efficient works program

An efficient works program balances business constraints, with the needs of the network and customers over a cycle of one to two years. The ability to deliver the works program is dependent on business case production, project planning, tendering, material delivery and field construction.

JEN's projects and programs are targeted for completion to deliver the best outcomes for the business and its customers. Drivers for works programming include the timely construction of performance improvement projects to achieve maximum customer value for the initiatives. Programmed asset replacement projects are performed before forecast end-of-life and demand projects are completed to ensure that sufficient network capacity is in place to meet forecast loads immediately prior to the critical summer loading period.

Where practicable, works on adjacent networks, transmission, subtransmission and distribution assets, capital projects, maintenance and seasonalised works program are aligned to maximise efficiency – for both cost and deliverability.

Improve facilities

JEN has proposed expenditure for the redevelopment of its work depots located at Broadmeadows and Sunshine. The redevelopment proposal is considered in the context of establishing a Melbourne North site which would operate as Electricity North Operations to service JEN's network. To optimise JAM's performance is satisfying the network obligations, the options were considered against the following requirements:

- *OHS&E* – overcome the current operational concerns and deficiencies with the Broadmeadows site
- *Operational* – achieve operational efficiencies, performance improvements and the right amenity in the right location to attract and retain staff

- *Capacity* – the need to accommodate the scope and specifications of the Broadmeadows and Sunshine operations, including integration of JEN related staff currently at Mt Waverley and Clayton and the capacity to support forecast network growth.

8.8.3 Non-network alternatives

The Distribution Code requires JEN to publish an annual Distribution System Planning Report that identifies its network locations that have capacity constraints, proposes network solutions and invites non-network alternatives to alleviate the constraints. Each report is for the following five years. JEN publishes these reports annually and seeks expressions of interest from non-network proponents.

JEN's current demand management program

The only non-network alternative implemented to date, in the current regulatory control period, is the Somerton Power Station. The power station is located in the Somerton area and consists of four 37.5MW gas fired generators and was connected into the TTS-SSS-ST-EPG-TTS 66 kV loop until October 2009 when the 66 kV network was re-configured. By entering into a network support agreement with JEN and SPI Electricity, the Somerton Power Station receives a network support payment from JEN and SPI Electricity for deferral of network augmentation at the transmission connection assets and the 66 kV network. The network support payment is expected to terminate by no later than November 2010, as the network support from Somerton Power Station will no longer be required at that time.

Most of JEN's proposed network augmentation projects have been foreshadowed in the 2008 Distribution System Planning Report. No proposals for non-network alternatives have been received to date. Therefore, no non-network alternative control projects are reflected in JEN's forecast capex for the forthcoming regulatory control period.

AER's demand management incentive scheme

Clause 6.12.1(4)(9) of the Rules provides that a distribution determination is predicated on the AER making a decision on how the demand management incentive scheme (amongst other matters) is to apply to JEN.

JEN proposes to adopt the DMIS as specified by the AER in its DMIS guideline.

There are therefore no variations or departures from the application of any component or part of the DMIS set out in the AER's F&A Paper.

8.8.4 Validation of capex forecasts

JEN engaged Deloitte to review the manner in which JEN relied upon the NIEIR demand forecasts when determining its capex forecast.

As set out in JEN's COWP and ITP, JEN has relied upon NIEIR's independently determined demand forecasts when developing its capex forecasts.

Deloitte reviewed the relevant JEN forecasting model to validate that JEN has used the NIEIR forecasts in this manner. A copy of Deloitte's report is provided in Appendix 7.11.

Network asset management plan review

GHD reviewed the capex and asset management practices of JAM to:

- review JEN's proposed network capex forecast over the forthcoming regulatory control period against the capital expenditure objectives and capital expenditure criteria of the Rules
- suggest further improvements where GHD considers them necessary or desirable.

Specifically, GHD assessed the JEN NAMP and associated capex to ascertain whether:

- it is such as would be incurred by a prudent operator in JEN's circumstances in order to determine compliance with clause 6.5.7(c)(2) of the Rules
- the costs represent efficient costs of achieving the capital expenditure objectives in order to determine compliance with clause 6.5.7(c)(1) of the Rules.

GHD concluded that:

'The capex forecasts and the explanations provided in the reviewed information would, in our opinion, comply with the requirements of the National Electricity Rules under rule 6.5.7(a) and rule 6.5.7(c)'[30]

IT plan review

JEN engaged Ernst & Young to review its IT capex program and forecast. Specifically, Ernst & Young was asked to review JEN's IT plan and proposed IT capex forecast over the forthcoming regulatory control period to ascertain whether:

- it is such as would be incurred by a prudent operator in JEN's circumstances in order to determine compliance with clause 6.5.7(c)(2) of the Rules

[30] Sinclair Knight Merz, *Victorian Distribution Network Service Providers annual material cost escalators 2010-15*, November 2009, p.1.

- the costs represent efficient costs of achieving the capital expenditure objectives in order to determine compliance with clause 6.5.7(c)(1) of the Rules.

Ernst & Young concluded that:

'In our opinion, nothing has come to our attention that causes us to believe that Jemena Electricity Networks' proposed IT capital expenditure, within the company's Electricity Distribution Pricing Review, has not complied, in all material respects, with the requirements of rules 6.5.7(a) and (c) of the National Electricity [Law and] Rules for the 2011 to 2015 regulatory period'

In its report, Ernst & Young also considered that:

'….the JEN estimate of $500,000 for Electric Content Management System training to be excessive and therefore not prudent and efficient. We do not believe that this excessive spend is material to the total IT capital expenditure of $67,852,789.'

JEN does not agree with Ernst & Young that forecast expenditure of $500,000 for Electronic Content Management System (that consists predominantly of training plus some costs for software licenses) does not appear to be prudent or efficient. JEN believes the expenditure is required to train JEN staff to use the increased intranet and internet capability that will result from JEN's IT Plan over the forthcoming regulatory control period. JEN will benefit from better access to information across many areas including emergency management, risk management, and occupational health and safety which will improve operational efficiency.

9 Forecast operating expenditure

This chapter provides JEN's forecast operating expenditure and explains how this regulatory proposal complies with the operating expenditure objectives, criteria and factors specified in the Rules. It also sets out the key assumptions that support JEN's forecast operating expenditure for the forthcoming regulatory control period and demonstrates compliance with RIN clause 4 and Rules clause 6.5.6 and s.6.1.2 and schedule s.6.1.3(c).

This chapter is structured as follows:

- *Summary* – provides an overview of JEN's proposed forecast opex requirements over the forthcoming regulatory control period
- *Context* – explains the aims and objectives, and documents relied upon by JEN in developing its opex forecasts
- *Opex forecasting process* – explains how JEN has developed its opex forecasts including the key assumptions around base costs, growth and input escalators that underpin JEN's opex forecasts as well as specific forecast items relating to debt raising costs and self insurance costs
- *Forecast opex by cost category* – sets out the JEN forecast opex in the cost categorisations required by the AER's RIN
- *Consistency with opex criteria, factors and objectives* – demonstrates how JEN's opex forecasts comply with the opex criteria, factors and objectives set out in the Rules
- *Other Rule considerations* – provides JEN's required explanation of the interaction between capex and opex forecasts, consideration of the reliability targets, the delineation of fixed and variable components and independent validation of the way JEN has reflected demand growth in its opex forecasts.

9.1 Summary

Opex is a major component of network expenditure accounting for approximately 30.1 per cent of JEN's total cost of service. JEN has forecast its opex with regard to the costs it will incur under its COWP, through its management structure and through its outsourcing of asset management activities. This structure and outsourcing are described in sections 2.7.

As discussed in chapter 5, JEN has achieved opex efficiencies totalling $54.4 million over the current regulatory period. JEN proposes to return these savings to its customers by adopting its 2009 costs as the base year for its opex forecast.

This base year approach is consistent with the incentive provisions inherent in the ESC's efficiency carryover mechanism and the AER's EBSS mechanism.

In conjunction with its network peers, JEN has engaged a number of experts (listed in 9.3.7) to determine the demand growth and input cost escalators that will affect its operating costs over the forthcoming regulatory control period.

Table 9-1: Forecast operating expenditure over the forthcoming regulatory control period by RIN category, (A$M, $2010)

Opex item	2011	2012	2013	2014	2015
Maintenance costs	22.4	22.6	22.8	23.3	22.9
Network operating costs	11.9	11.4	11.8	12.1	12.4
Billing & revenue collection	3.4	3.3	3.4	3.5	3.6
Customer service	3.8	3.6	3.7	3.8	3.9
Advertising, marketing & promotions	1.2	1.1	1.1	1.2	1.2
Regulatory	2.3	2.2	2.2	4.6	3.5
Other	17.7	17.0	17.7	18.2	18.6
GSL payments	0.0	0.0	0.0	0.0	0.0
Total	62.6	61.1	62.9	66.7	66.1

Note: GSL payments are positive, but due to rounding appear as zero.

9.2 Context

JEN has had regard to the operating expenditure objectives under Rule 6.5.6(a) when establishing its opex forecast (total, by category and material project). The opex forecast has also been informed by:

- JEN strategic objectives provided in Appendix 9.4
- AMA between JEN and JAM in Appendix 17.2
- NAMP and COWP provided in Appendix 9.1 and 10
- expert reports obtained from NIEIR, BIS Shrapnel, SKM, Evans & Peck, AECOM and Marsh Risk Consulting provided in Appendix 7.

In addition to these key inputs, JEN's opex forecasts also reflect the various internal business policies and procedures set out in RIN template 6.4.

JEN has adopted the well-established regulatory precedent of rolling-forward its revealed 2009 opex costs to establish its forecast of the majority of its recurrent opex costs over the forthcoming regulatory control period. Where necessary, it has supplemented this approach with bottom-up estimates of costs that are one off or not reflected in JEN's reported cost bases, for example:

- step changes to existing activities
- self insurance
- debt raising costs.

In developing its opex forecasts JEN has had regard to its:

- service obligations set out in chapter 3
- service performance targets set out in section 7.2
- safety and operating regulations and obligations set out in section 3.2.

The resulting opex forecasts presented in this chapter relate to all distribution services falling within standard control services.

JEN has prepared its opex forecast in accordance with its proposed CAM. A copy of this CAM is provided in Appendix 8.

JEN's opex forecasts are arrived at on a reasonable basis and represent the costs of a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering its services.

9.3 Opex forecasting process

JEN's opex, by category and total, is forecast by adding:

- the expected fee that JEN will pay to JAM for asset management (inclusive of a negotiated margin) under the new AMA
- JEN's other expected costs (including its own direct costs and its allocation of Jemena's overheads).

JEN has used the base year approach to forecast JAM's asset management fee and to forecast JEN's other costs as set out below. Together these costs account for 96.3 per cent of JEN's total opex forecast for the forthcoming regulatory control period.

JEN has developed specific forecasts for the remaining 3.7 per cent of its opex costs using forecasting approaches that it has tailored to each cost.

9.3.1 Step 1 – Gather information on the current and historic opex

JEN's base year is the calendar year 2009. For the purpose of this regulatory proposal JEN has had to develop a proxy base year cost estimate as the actual 2009 data is not yet available.

By the time the AER makes its draft determination, JEN will be able to determine its 2009 base year using actual costs as stated in its 2009 regulatory accounting statements due in April 2010.

For the purposes of this regulator proposal, and consistent with the manner in which it has prepared its regulatory accounts, JEN built up its own base year cost by combining JAM's underlying costs (exclusive of the margin JEN paid) and JEN's other direct and corporate costs.

JAM underlying costs

The JAM opex costs are established as follows:

- JAM's direct opex costs of serving JEN
- JAM's direct overheads
- JAM's indirect overheads or corporate costs.

JEN other direct and corporate costs

The other JEN costs are established as follows:

- JEN's direct opex costs not incurred through the AMA with JAM
- JEN's indirect overheads or corporate costs.

9.3.2 Step 2 – Adjust the base year

JEN made the necessary adjustments the costs identified in step 1 to enable them to be used in forecasting future years costs by:

- subtracting costs associated with one-off events during 2009 and circumstances that are not expected to endure

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- adding the increment between the 2009 and 2010 opex forecasts established by the ESC in order to preserve the incentive properties of the EBSS

- adding costs associated with foreseeable incremental step changes in expenditure, where:

  – the step changes reflect increases or decreases in costs due to new regulatory obligations, or changes in the operating environment that are outside the JEN's control, such as climate change policies

  – other changes reflect incremental opex adjustments arising from JEN proposed capital program.

9.3.3 Step 3 – Roll the base year costs forward

JEN then rolled its adjusted base year costs forward, adjusting again (escalating or deflating) using forecasts of:

- the impact of network growth (customer numbers, energy usage and system peak demand) on the amount of work that will need to take place

- the real change in the input costs for doing the work (real escalation in the costs of labour and materials)

- inflation.

9.3.4 Step 4 – Develop tailored forecasts for non-base year items

Finally, JEN prepared specific forecasts for items not suited to a base year roll forward approach. This lack of suitability arose from costs either not being reflected in historic base costs such as individual step changes, or the existence of tailored forecasting techniques such as debt raising costs.

The results of the above steps are discussed below. Table 9.2 summarises the key assumptions JEN relied upon. Because JEN has adopted a base year roll forward approach, these key assumptions relate to both the aggregate opex forecast as well as the category level forecasts. The only exceptions relate to self-insurance, debt raising costs and fees and claims, which are discussed in section 9.3.5.

Table 9-2: Opex key assumptions

Key assumption	Method used to develop assumption	How JEN has applied this assumption	Relationship to capex assumptions
Base year costs	JEN has relied upon its expected 2009 outcome. This has been informed by the Jemena WOBCA set out in Appendix 7.3.	JEN used 2009 as the starting point for forecasting as described in section 9.3	Not applicable
Step changes	JEN has explained how each of its step changes was developed in the COWP and ITP, attached as Appendix 10 and Appendix 9.2 • COWP section 1.7 – step change identification framework • COWP section 3.1.5 – asset management step changes • COWP section 3.2.4.1 – operating and maintenance step changes • COWP section 3.4.1 – JEN non O&M step changes • ITP section 6.3 – IT step changes	JEN used step changes to adjust base year costs for the purpose of forecasting as described in section 9.3	Not applicable
Demand growth	JEN has obtained independent expert demand forecasts from NIEIR. NIEIR has forecast demand taking into account its expert view of key economic, policy and market drivers. These forecasts and the methods for their development are set out in Appendices 7.4 and 7.5.	JEN adopted the ESC determined demand related growth adjustment as described in section 9.3.4	Common NIEIR forecasts were employed in capex and opex forecasting
Labour cost escalation	JEN engaged BIS Shrapnel to forecast labour input cost escalation for internal labour and external contractor	JEN escalated the labour shares of its base year costs using the BIS	Common BIS Shrapnel forecasts were employed in

Key assumption	Method used to develop assumption	How JEN has applied this assumption	Relationship to capex assumptions
	labour. BIS Shrapnel forecast labour costs taking into account its expert view of key economic and labour market drivers. These forecasts and the methods for their development are set out in Appendix 7.2.	Shrapnel forecasts as described in section 9.3.4	capex and opex forecasting
Materials input escalation	JEN engaged Sinclair Knight Mertz (SKM) to forecast materials input cost escalation in Appendix 7.1. SKM forecast costs using its electricity network survey data and assessment of futures data for relevant commodities.	JEN escalated the materials shares of its base year costs using the SKM forecasts as described in section 9.3.4	Common SKM forecasts were employed in capex and opex forecasting

The following section details the application of JEN's opex forecasting process.

9.3.5 Step 1: Collecting historical base year costs

Given that JEN's actual cost data for the full 2009 year is not yet available, JEN has had to develop a proxy base year cost estimate. Due to the complexities in gaining a holistic view of costs, JEN has developed its base year estimate using a composite of actual and forecast data from the preceding period as set out in Table 9-3.

JEN considers this method provides the best estimate available in the current circumstances. JEN also notes that this will be updated for actual costs during the review process after JEN submits its 2009 regulatory accounting statements on 30 April 2009.

Table 9-3: Basis of JEN 2009 cost estimate

Cost item	Description of source
JAM direct costs	2009 actual to Sep and estimate to Dec
JAM indirect costs	2008 actual escalated to 2009
JAM corporate costs	2008 actual escalated to 2009
JEN non-JAM direct costs	2009 actual to Sep and estimate to Dec
JEN corporate costs	2008 actual escalated to 2009

Jemena conducted a Whole of Business Cost Allocation (**WOBCA**) project to collect and quantify direct and indirect costs associated with JEN's service provision using the best available information from its historical records. Appendix 7.3 details the WOBCA method.

The nature of JEN's 2009 historical costs reflects the nature of JEN's outsourcing at the time and a previous corporate structure. To enable JEN to fully apply its roll-forward approach, the WOBCA process broke down and quantified JEN's direct costs and overheads, and JAM's underlying direct costs and overheads. This has enabled each type of cost to be adjusted and/or rolled forward separately.

Expert review of WOBCA

In its expert report in Appendix 7.3, PricewaterhouseCoopers (**PwC**) describes the WOBCA process and verifies the robustness of the cost allocation method and the results. PwC concluded that:

- the WOBCA method is simple, justifiable, transparent, consistent and auditable
- for all costs allocated to JEN, the WOBCA method has been accurately applied
- cost allocations are consistent with clause 6.5.6(b) of the Rules
- notwithstanding the difference in time period, the WOBCA method has been consistent applied to JEN as it was in a previous application to JGN.

9.3.6 Step 2: Adjusting the base year

JEN considers that, subject to the adjustments described below, its base year costs are representative of a typical year and therefore suitable as a basis for forecasting purposes.

One-off events

JEN and JAM have identified a number of costs which are not representative of a typical year of recurrent opex costs. These relate to items which are one-off in nature or will likely be higher in 2009 than may be the case in a typical year. These one-off costs are shown in Table 9-4.

Table 9-4: One-off opex costs ($million, $2009)

Item (2009 $m)	Description	One-off cost
JAM		
Branding	Costs associated with the development and roll out of the Jemena brand	0.66
SPI Employee Costs		0.04
One-IT	The development and implementation of a shared SP AusNet & Jemena IT delivery service, implemented through the establishment of EBS	0.79
Dove / Warrnambool		0.20
BRP Blueprint	Business process review project incorporating the standardisation of business processes such as costing and estimating, and time writing	0.36
Other		0.02
JEN		
Network support payment	Avoided cost Distribution payment to AGLPG	0.11
Accounting one-offs	Doubtful debts and interest on over/under recovery (for DUoS revenue)	0.04
Total one-off costs		**2.21**
Total one-off costs (2010 $m)		**2.24**

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5th year forecast increment from EBSS

The AER's EBSS Final decision identifies that:

- the AER recognises that efficiency carryover schemes are currently operating in some jurisdictions which some DNSPs are subject to. The AER will calculate and apply the carryovers for these existing schemes in its first revenue determinations for these DNSPs in accordance with the prevailing jurisdictional arrangements in place[31]

- an important element of the ESC's efficiency carryover mechanisms is the provision of even efficiency incentives in each year of the regulatory period. In order to achieve this when making a regulatory determination before the final year efficiencies are known, the ESC employed a final year regulatory adjustment equation (**FYRAE**).

This equation had two parts:

- constraining the year five carryover amount to zero by adding the difference between the ESC's approved forecast opex for years four and five of the regulatory period to the network's reported year four costs

- adding this same increment or decrement to the base year costs when determining the forecast opex allowance for the forthcoming regulatory control period.

[31] AER, *Final Decision Efficiency Benefit Sharing Scheme*, June 2008, p. 13.

Adding the increment between the 2009 and 2010 opex forecasts established by the ESC to preserve the incentive properties of the EBSS requires JEN to add $1.5 million.

Step changes

JEN and JAM have identified items that will affect JEN's future cost base that are not in the base year. These items represent step changes in JEN's operating environment and regulatory obligations—for example, changes in standards, compliance requirements, and new asset types with new operational and maintenance requirements. They total $11.2 million per year over the forthcoming regulatory control period.

JEN's COWP provided in Appendix 10 details the individual step change items, their causation and the basis of their forecast cost.

Capital program related changes

JEN and JAM have identified incremental opex items arising from JAM's proposed capital program. These relate to JEN significant asset replacement program and the associated additional asset inspections JEN has scheduled to optimise the timing of asset replacement, and extend asset lives where possible.

Section 3.2.4.2 of JEN's COWP provided in Appendix 10 details the individual items, their causation and the basis of their forecast cost. They total up to $0.2 million per year.

9.3.7 *Step 3:* Rolling forward the base year

This section sets out JEN's key forecasting assumptions, including its opex escalators.

Growth in consumption and customer connections

Many of JEN's operating activities and costs grow in line with the growing demand for its network services. To determine its reasonable forecasts of growth in consumption, customer connections and peak demand, JEN has drawn upon independent expert reports from NIEIR (provided in Appendices 7.4 and 7.5).

During the 2005 EDPR, the ESC engaged Pacific Economists Group (**PEG**) to assess the multifactor productivity and output growth drivers of the Victorian electricity distributors[32].

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[32] ESC, *Electricity Distribution Price Review 2006-10, October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006, Final Decision Volume 1 Statement of Purpose and Reasons*, October 2006, section 6.2.4.

JEN has employed the weighted opex growth rate for consumption, customer connections and peak demand determined by the ESC to roll forward its base opex costs for growth using the NIEIR forecasts.

Labour cost escalation

In conjunction with the other Victorian electricity distributors, JEN commissioned BIS Shrapnel to forecast labour rate escalation factors in order to forecast changes in the labour costs of JEN's proposed expenditure for the forthcoming regulatory control period. BIS Shrapnel produced forecasts for both internal labour and external labour. Table 9-5 summarises BIS Shrapnel's forecasts and its report is provided in Appendix 7.2.

Table 9-5: Opex labour escalation factors for JEN (per cent)

Opex	2010	2011	2012	2013	2014	2015
Internal labour	3.84%	2.43%	2.63%	2.73%	2.63%	2.43%
External labour	3.04%	1.93%	2.63%	3.03%	2.53%	2.33%

Materials cost escalation

In conjunction with the other Victorian electricity distributors, JEN commissioned Sinclair Knight Mertz (**SKM**) to estimate cost escalation factors in order to forecast changes in the input costs of JEN's proposed expenditure for the forthcoming regulatory control period. SKM's terms of reference requested that it develop cost escalation factors for aluminium and steel.

SKM's estimates of input cost escalation factors are set out in Table 9-6. SKM's report is included in Appendix 7.1.

Table 9-6: Opex escalation factors for JEN (per cent real)

Opex	2010	2011	2012	2013	2014	2015
Aluminium	18.52%	7.67%	6.20%	6.40%	5.98%	5.67%
Steel	22.72%	9.53%	4.25%	1.65%	1.72%	1.60%

SKM observe that the method is consistent with the method applied by the AER in its calculation of escalation factors for its final determinations for the New South Wales DNSPs.[33]

[33] Sinclair Knight Merz, *Victorian Distribution Network Service Providers annual material cost escalators 2010-15*, November 2009, p.1.

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Accounting for alternative control services

JEN has deducted its alternative control service costs from the total opex forecast.

9.3.8 Step 4: Develop tailored forecasts for non-base year items

For certain cost items JEN adopted a specific cost forecasting approach instead of the base cost roll forward. JEN employed this approach for the following items where there was either insufficient historic information to use a base roll forward approach, or where dedicated expert opinions were employed:

- step changes detailed in JEN's COWP at Appendix 10 and ITP at Appendix 9.2
- self insurance
- debt raising costs.

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Debt and equity raising costs

Jemena incurs costs when it raises funds, both debt and equity, to spend on JEN’s capital program.

Debt raising costs are incurred each time debt is rolled over, and may include underwriting fees, legal fees, company credit rating fees and other transaction costs.

Equity raising costs are incurred each time equity is raised and may include legal fees, brokerage fees, underwriting costs, marketing costs and other transaction costs. These are upfront expenses, with little or no ongoing costs over the life of the equity.

For consistency with the Rules, JEN proposes debt and equity raising costs that would apply to a benchmark efficient firm that:

- has JEN's proposed RAB including its capital program
- maintains a constant leverage ratio of 60 per cent throughout the forthcoming regulatory control period.

JEN proposes benchmark efficient:

- debt raising costs of 0.12 per cent per year on its outstanding debt balance at the start of the year
- equity raising costs of 1.0 per cent on equity raised internally (through dividend reinvestment) and 7.0 per cent on equity raised externally—assuming a dividend payout ratio of 66.0 per cent consistent with JEN's proposed gamma (see chapter 12) and a dividend reinvestment take-up rate of 30 per cent
- JEN proposes expensing debt raising costs as an administration and overhead cost and capitalising equity raising costs to its RAB with a standard life equal to the value-weighted average standard life of JEN's capital plan.

JEN estimates equity raising costs of $1.7 million over the forthcoming regulatory control period. Hence, JEN proposes to add this value to its opening RAB in 2011.

9.4 Forecast opex by category

Table 9-9 summarises JEN's forecast opex reflecting the manner in which it was forecast.

Table 9-9: JEN forecast opex by forecast method over forthcoming regulatory control period

	Adjusted base year	Estimate	Forthcoming regulatory control period				
Category	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Activities provided by JAM							
Step changes	0.0	3.9	10.8	8.2	8.7	8.9	8.2
Less Alternative Control Services	-8.6	-8.6	-8.6	-8.5	-8.5	-8.5	-8.5
Other JEN operating costs							
Base cost	8.6	8.7	8.7	8.8	8.9	9.0	9.0
Step changes	4.0	2.8	1.8	1.6	1.5	3.8	2.8
Debt raising	0.0	0.0	0.5	0.6	0.6	0.7	0.7
Fees and claims	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Total JEN opex	**51.0**	**55.2**	**62.6**	**61.1**	**62.9**	**66.7**	**66.1**

Notes: base costs are net of one-off events.

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JEN has categorised its operating costs into the categories prescribed by the AER's RIN. Table 9-1 sets out JEN forecast costs against these categories.

As identified by JEN during pre-consultation with the AER, certain of the cost categories prescribed by the AER have required JEN to make cost allocations and apportionments. Table 9-10 summarises how JEN has categorised costs against each category. A full explanation of all assumptions underpinning these categorisations is included in JEN's RIN templates in Appendix 6.

Table 9-10: Opex cost categorisation

Opex item	Activities covered	Basis of cost categorisation
Network operating costs	The costs reported in this category have been based on the definitions in the ESC's Guideline 3 on the preparation of annual Regulatory Accounts. The costs typically include staffing of the control centre, outage planning personnel, demand forecasting, procurement, logistics and stores, related IT costs, insurance & tax.	Opex costs for 09-15CY have been allocated using the proportional split from the 2008CY regulatory accounts (adjusted for selected items as noted below).
Billing & revenue collection	Based on Guideline 3. The costs typically include invoicing (billing), accounts receivable and costs associated with the Customer Information System (CIS) and other IT costs allowed under Guideline 3 in relation to these functions.	Opex costs for 09-15CY have been allocated using the proportional split from the 2008CY regulatory accounts (adjusted for selected items as noted below)
Customer service	Based on Guideline 3. The costs typically include the provision of the following services to distribution customers - facilitating reporting of network faults and safety matters, responding to retailer requests on new connections, disconnections, reconnections etc and CIS and other IT costs allowed under GL3 in relation to these functions.	Opex costs for 09-15CY have been allocated using the proportional split from the 2008CY regulatory accounts (adjusted for selected items as noted below)
Advertising, marketing & promotions	Based on Guideline 3. The costs typically include the development of network tariffs, communications with distribution customers in a range of matters including fault reporting, reliability targets, planned supply interruptions, public safety and IT costs relating to these functions.	Opex costs for 09-15CY have been allocated using the proportional split from the 2008CY regulatory accounts (adjusted for selected items as noted below)
Regulatory	Based on Guideline 3. The costs typically include licence fees, costs of the regulatory function including the regulatory manager and her team, preparing regulatory submissions and providing information sought by regulators, costs of non-financial audits, etc.	Opex costs for 09-15CY have been allocated based on the proportional split of the 2008CY regulatory accounts (adjusted for selected items) with the costs of the EDPR project included in the relevant years

Opex item	Activities covered	Basis of cost categorisation
Other	Based Guideline 3. The costs typically include the costs of the finance function, fleet management and administration, Human Resources, IT costs not accounted for in other cost categories, Corporate Services including legal, and other overhead services not reported elsewhere.	Opex costs for 09-15CY have been allocated using the proportional split from the 2008CY regulatory accounts (adjusted for selected items as indicated)
GSL payments	These amounts are recorded in a specific general ledger account in the SAP accounting system	As per the General Ledger account forecast

Note: JEN's opex costs and categorised activities presented in this proposal exclude licence fees paid to the ESC. This is because these are subject to an existing pass through provision which JEN proposes to retain into the forthcoming regulatory control period.

9.5 Consistency with opex criteria, factors and objectives

JEN's opex forecasts by total, category and material project are made on a reasonable basis and have been developed to comply with the operating expenditure objectives and operating expenditure criteria and to address the operating expenditure factors specified in the Rules.

9.5.1 Operating expenditure objectives

JEN has established its opex forecasts to comply with the operating expenditure objectives specified in the Rules. JEN has primarily achieved this by:

- examining its current base year costs incurred in meeting current service level and regulatory obligations
- assessing the sufficiency of its current compliance with regulatory obligations to identify step changes for corrective actions
- assessing foreseeable new or changed obligations that will affect its operating activities and costs to identify step changes
- incorporating escalation for expert determined demand growth and input cost escalation.

Table 9-11 summarises how JEN has complied with the operating expenditure objectives.

Table 9-11: Operating expenditure objectives

Operating expenditure objective	Rule	JEN actions to ensure compliance
Meet or manage the expected demand for standard control services	6.5.6(a)(1)	JEN has adjusted its forecast costs to take into account the weighted growth effects of expert determined peak demand, customer number and consumption forecasts.
Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services	6.5.6(a)(2)	JEN has assessed its current compliance (and associated base costs) as well as assessing corrective actions and additional new obligations (and associated step changes)
Maintain the quality, reliability and security of supply of standard control services	6.5.6(a)(3)	JEN has prepared a comprehensive COWP and NAMP with associated expenditure forecasts
Maintain the reliability, safety and security of a distribution system through the standard control services	6.5.6(a)(4)	JEN has prepared a comprehensive COWP and NAMP with associated expenditure forecasts

9.5.2 Operating expenditure criteria

Current costs are efficient due to existing incentives

In the current regulatory control period, JEN has had an incentive to minimise its costs overall to maximise its commercial position. This incentive has been created by the fixed opex allowance and price cap that the ESC provided to JEN in 2005. Similarly, the fixed fee that JEN has paid JAM up to 2009 has provided JAM with incentive to minimise its costs. These incentives have been further supported by the operation of the ESC's efficiency carryover mechanism.

Given these incentives, the AER can infer that the base year build up of costs for JEN and the underlying costs of JAM are efficient.

Future costs are efficient due to prudent commercial outsourcing

JEN has in-house functions to manage its costs and its outsourcing of asset management activities. Through this model, and in accordance with a formal commercial process, JEN has negotiated an asset management agreement with JAM that reflects JEN's interests in containing its costs and in ensuring that JAM provides a level of service that reflects good industry practice.

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Further, JEN has secured contractual incentive arrangements that align JAM's incentives with those of JEN as regards both cost and service performance. These arrangements represent those of a prudent operator. Together with the use of independent expert cost driver inputs, they enable the AER to infer that JEN's costs over the forthcoming regulatory control period represent the efficient costs of a prudent operator in JEN circumstances.

Forecast methods reflect realistic expectations of demand and input costs

JEN's application of the base year roll-forward and approach to the majority of JEN's opex forecast, and its year-by-year forecasts of other specific costs is reasonable and based on the best information available, including:

- Jemena's internal cost information and allocation method, which PwC has verified as reasonable

- reliable expert reports from NIEIR, SKM and BIS Shrapnel that provide reasonable demand forecasts and estimates of cost escalators.

9.5.3 Operating expenditure factors

The Rules set out the operating expenditure factors which the AER must have regard to when deciding whether or not to approve JEN's opex forecast. Table 9-12 summarises points JEN considers relevant to these factors.

Table 9-12: Operating expenditure factors

Operating expenditure objective	Rule	JEN comments
the information included in or accompanying the building block proposal	6.5.6(e)(1)	JEN has provided a comprehensive regulatory proposal supported by extensive appendices, financial models and RIN templates
submissions received in the course of consulting on the building block proposal	6.5.6(e)(2)	
analysis undertaken by or for the AER and published before the distribution determination is made in its final form	6.5.6(e)(3)	
benchmark operating expenditure that would be incurred by an efficient Distribution Network Service Provider over the regulatory control period	6.5.6(e)(4)	
the actual and expected operating expenditure of the Distribution Network Service Provider during any preceding regulatory control periods	6.5.6(e)(5)	JEN has provided its actual historic expenditure in chapter 5 and in the relevant RIN templates.
the relative prices of operating and capital inputs	6.5.6(e)(6)	JEN relies on lifecycle management planning for each asset, which considers all strategies and options over the entire asset life from planning to disposal to deliver the lowest long-term cost. Lifecycle management focuses on ensuring effectiveness and efficiency in maintenance (opex) and replacement (capex) of the network assets based on reliability centred maintenance analysis and considers issues of safety, cost, risk and reliability. Additionally, JEN has relied upon the same input cost escalators for capex and opex.

Operating expenditure objective	Rule	JEN comments
the substitution possibilities between operating and capital expenditure	6.5.6(e)(7)	JEN has assessed these opportunities and has proposed: • an enhanced asset inspection program (opex) to complement the asset replacement strategy (capex) • several IT capex projects that provide for corresponding savings in IT opex costs over the forecast period.
whether the total labour costs included in the capital and operating expenditure forecasts for the regulatory control period are consistent with the incentives provided by the applicable service target performance incentive scheme in respect of the regulatory control period	6.5.6(e)(8)	All significant proposals to commit funds are subject to an economic evaluation. All realistic options are included in the analysis. All costs, savings (both capital and operation/maintenance) and revenues relevant to each option are included in evaluations. These revenues include an assessment of the impact of the STPIS.
the extent the forecast of required operating expenditure of the Distribution Network Service Provider is referable to arrangements with a person other than the provider that, in the opinion of the AER, do not reflect arm's length terms	6.5.6(e)(9)	As discussed in Appendix 17 and demonstrated by the AMA, JEN has established outsourcing arrangements that reflect prudent commercial terms.
the extent the Distribution Network Service Provider has considered, and made provision for, efficient non-network alternatives	6.5.6(e)(10)	JEN's base costs include costs for avoided network costs paid to the Somerton distributed generator. JEN proposes to continue these network support arrangements until their expiry in Oct 2010. There are seven embedded generators inter-connected to the network – Somerton Power Station in Somerton, Brooklyn Landfill in Brooklyn, Bolinda Landfill in Broadmeadows, Austin Hospital in Heidelberg, LaTrobe University in Preston, Mini Hydro in Preston and Australian Paper in Fairfield. In forecasting peak demand for zone substations with embedded generation, it is assumed that the generators are running at peak load periods

		unless otherwise specified. JEN publishes opportunities for non-network solutions in its annual planning reports and invites non-network solution proponents to contact JEN. These documents are published in order to provide transparency and information to the wider energy industry, with a specific objective of seeking opportunity for non-network solutions to defer the need for network investment.

9.6 Other Rule considerations

9.6.1 Interaction between capex and opex forecasts

JEN manages capital expenditure through an active risk management process, where capital and maintenance expenditure are optimised to meet a balance between acceptable risk and returns within its cash flow requirements. JEN's COWP details both its capital and operating activities over the forthcoming regulatory control period.

A key feature of JEN's capital program is the significant program of work to address asset aging. This program has been developed for an optimal life cycle management and includes a targeted combination of:

- asset replacements (capex)
- enhanced asset inspections (opex).

In addition, JEN's ITP includes significant capital investment in new and replacement IT systems for which JEN has identified associated positive and negative opex step changes where relevant.

9.6.2 Reliability targets

As discussed in section 7.2, JEN has set it proposed reliability targets in accordance with the AER's proposed STPIS method. JEN had regard to these targets when setting its opex allowance by assessing the sufficiency of its current performance to identify step changes for corrective actions.

JEN has not forecast any planned maintenance programs that are designed to improve is service reliability. JEN has focussed its COWP on maintaining reliability at the levels required by the STPIS targets. JEN notes that any additional reliability improvement investments and initiatives will be assessed on a case by case basis and funded through the incentives available under the STPIS.

9.6.3 Fixed and variable components

The forecast horizon of 2011 to 2015 may be characterised in economic terms as the short run. This is because in this time period, JEN will incur both:

- variable costs that will change as JEN's output of customer numbers, consumption and peak demand changes
- fixed costs which by their nature will be incurred regardless of movements in JEN's outputs.

The fixed and variable costs may be considered end points on a range of cost characteristics. Within this range, JEN will incur costs that vary on a one-for-one basis with certain outputs as well as costs that will vary in a stepped nature. Notwithstanding this, Table 9-13 shows those operating activities for which JEN's costs may broadly be characterised as either variable or largely fixed. JEN does not have access to information in a form suitable for identifying fixed and variable costs for each separate RIN category.

Table 9-13: Fixed and variable cost items

Nature of costs	Examples of JEN activities
Fixed	Corporate support costs including finance, regulatory management, human resources, legal and business support services. Engineering asset management functions Licence fees
Variable	Network planned maintenance costs Customer service costs such as those provided through the customer contact centre

Note: Classification as 'fixed costs' does not mean that these costs will not experience cost escalation over a given period. For example, a fixed activity may involve five full time equivalent staff (FTEs). While the FTE count may be fixed regardless of output growth, JEN would still reasonably expect to incur cost growth due to wages growth for those five FTEs.

9.6.4 Validation of opex forecasts

JEN engaged Deloitte to review the manner in which JEN relied upon the NIEIR demand forecasts when determining its opex forecast.

As set out in section 9.3.4, JEN relied upon the ESC opex cost growth weights and the NIEIR demand forecasts for peak demand, customer numbers and energy consumption to determine a weighted growth factor. JEN then applied this growth factor to its 2009 base opex costs to escalate these for output growth over the forthcoming regulatory control period.

Deloitte reviewed the relevant JEN forecasting model to validate that JEN has used the NIEIR forecasts in this manner. A copy of Deloitte's report is provided in Appendix 7.11.

10 Regulatory asset base

This chapter sets out the method used to roll forward JEN's RAB, its forecast capital contributions and disposals, and provides a summary of the resultant RAB outcomes over the forthcoming regulatory control period, in compliance with RIN clause 5, Rules clauses 6.4.3, 6.5, 6.21, and Schedules 6.1.3 and 6.2.1.

This chapter is structured as follows:

- *Summary* - provides an overview of JEN's proposed RAB roll forward over the forthcoming regulatory control period
- *Customer contributions* – provides JEN's forecast customer contributions over the forthcoming regulatory control period
- *Asset disposals* – sets out JEN's forecast asset disposals over the forthcoming regulatory control per
- *Establishing RAB at 1 January 2011* – establishes RAB at 1 January using the ESC's method as required under the Rules
- *Resulting RAB values over the forthcoming regulatory control period* – provides details of JEN's RAB values over the forthcoming regulatory control period.

10.1 Summary

JEN has determined that its RAB as at 1 January 2011 is $755.6 million and is forecast to be $1,098.6 million at 31 December 2015, as shown in Table 10-1. Assets in JEN's RAB are used for the purpose of providing standard control services.

JEN has established its RAB as at 1 January 2011 in accordance with the requirements of Schedule 6.2.1 of the Rules and for the forthcoming regulatory control period to 31 December 2015 by applying the RAB roll-forward method specified in the roll forward model which JEN provided to the AER on 17 November 2009 in lieu of the AER publishing a roll forward model that complies with the transitional provisions of the Rules.[34]

[34] JEN notes the AER's acknowledgement that the AER's roll forward model in the form published under clause 6.5.1 of the Rules is not fit for Victorian DNSP's purposes. It is not possible for JEN to use the roll forward model and also comply with the substantive requirements of the Rules as they apply to Victorian DNSPs. JEN considers that its amended roll forward model complies with all relevant requirements of the Rules and, except as necessary to meet these requirements, is otherwise consistent with the AER's published roll forward model.

Table 10-1: Forecast RAB over the forthcoming regulatory control period

	2011	2012	2013	2014	2015
Opening RAB 1 January	755.6	840.9	923.2	989.9	1,042.8
Forecast capital expenditure/ additions	146.9	149.1	141.5	128.9	131.4
Customer contributions	13.5	13.6	14.5	15.1	15.6
Disposals	2.3	0.1	0.1	0.1	0.1
Depreciation	45.9	53.0	60.1	60.8	59.8
Closing RAB 31 December	**840.9**	**923.2**	**989.9**	**1,042.8**	**1,098.6**

Note: forecast capital expenditure includes a half year of real vanilla WACC, in accordance with the PTRM.

10.2 Customer contributions

In most cases where a customer requests a new or changed service, it will be necessary for JEN to expend capital to meet the request (customer-initiated capex).

Historically, JEN has requested a capital contribution from the customer where the present value of incremental costs associated with meeting the customer's request (including capital and ongoing operating and maintenance costs) exceeds the present value of the incremental revenue that will be generated by the new or changed service (based on the distribution tariff to apply). JEN calculates the amount of any customer contribution in accordance with the ESC's Electricity Industry Guideline No 14, Provision of Services by Electricity Distributors, Issue No 1, April 2004.

Amounts received as customer contributions during the previous and current regulatory control periods are shown in Table 10-2 and Table 10-3 respectively. JEN has excluded these from the RAB.

Table 10-2: Customer contributions previous regulatory control period

	2001	2002	2003	2004	2005

	2001	2002	2003	2004	2005
Total	**13.4**	**17.3**	**17.2**	**14.4**	**12.1**

Table 10-3: Customer contributions current regulatory control period

	2006	2007	2008	2009	2010
Total	**8.8**	**10.9**	**12.1**	**9.7**	**13.5**

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For the forthcoming regulatory control period, JEN has developed the forecast customer contributions by applying the proportion of current customer contributions to current customer initiated capex to forecast customer initiated capex. Table 10-4 shows JEN's forecast customer contributions. This forecasting method means JEN's forecast contribution proportions are all within 10 per cent of the current period outcome.

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Table 10-4: Customer contributions forthcoming regulatory control period

	2011	2012	2013	2014	2015
Total	**13.7**	**13.7**	**14.6**	**15.1**	**15.7**

None of the customer contributions in the previous, current or forthcoming regulatory control periods are attributable to the Victorian Government's Powerline Relocation Scheme. None of the customer contributions are attributable to wind farm related connection capex funded under the Electricity Industry Act 2000 (Vic).

10.3 Asset disposals

JEN has forecast the proceeds on the sale of assets based on historical asset sale proceeds for the years 2005 to 2008 broken out by activity codes. The historic average was adjusted for one off sales unlikely to be repeated in the forecast period. It is assumed that fully depreciated assets will have no resale value.

10.4 Establishing RAB at 1 January 2011

JEN has established the value of its RAB as at 1 January 2011 to be $755.6 million ($nominal) by applying the method prescribed in Schedule 6.2.1 of the Rules. That is, the opening RAB in the current regulatory control period ($578.4 million as at 1 January 2006 in $July 2004[35]) has been rolled forward in accordance with Schedule 6.2.1(e) of the Rules after adjustment for:

35 Schedule S6.2.1(c)(1) of the Rules.

1. the difference between forecast and actual net capital expenditure[36]

2. inflation between July 2004 and January 2006

3. regulatory depreciation[37]

and where expenditure on connection services during the current regulatory control period has been allocated to the provision of *standard control services* (Schedule 6.2.1(e)(4)) on the basis that connection services are classified as *standard control services* for the current regulatory control period.

The value of the RAB is consistent with the value of the assets used to provide standard control services, to the extent they are used to provide those services. Table 10-5 shows JEN's adjusted RAB

Table 10-5: Adjustment to JEN's 2005 closing RAB

	Closing RAB 31 December 2005
ESC 2005 determination	694.7
Adjustment for capex underspend	-33.2
Adjusted RAB	661.5

Note: Values are inflated to 31 December 2010 to align with the PTRM.

Table 10-6 shows JEN's RAB roll forward calculation from 2006 to 2010.

Table 10-6: RAB over the current regulatory control period

	2006	2007	2008	2009	2010
Opening RAB 1 Jan	661.5	682.2	703.6	699.8	710.2
Forecast capital expenditure/ additions	73.0	77.1	54.8	66.5	105.9
Customer contributions	8.4	10.2	11.6	9.2	13.0
Disposals	0.5	0.6	1.3	0.0	0.1
Depreciation	43.2	44.9	45.7	46.9	47.4
Closing RAB 31 Dec	682.2	703.6	699.8	710.2	755.6

Note: Values are inflated to 31 December 2010. Actual values are used up to 31 March 2009 and forecast values thereafter except for regulatory depreciation where forecast values are used in all years.

[36] Schedule S6.2.1(c)(2) of the Rules, and ESC, Final Decision, October 2005, p. 324.

[37] Schedule S6.2.1(c)(1) of the Rules.

10.5 Resulting RAB values over the forthcoming regulatory control period

For the forthcoming regulatory control period, JEN has rolled forward the 1 January 2011 opening RAB value by applying the roll forward model provided to the AER on 17 November 2009. The results are shown in Table 10.1.

11 Depreciation

This chapter complies with Rules clauses 6.4.3(3), 6.5.5, and Schedule 6.1.3(12) by setting out the method used by JEN to calculate its depreciation allowance in the building block revenue proposal for the forthcoming regulatory control period. It also sets out the standard and remaining lives of JEN's network system and non-system assets.

This chapter is structured as follows:

- *Summary* - summarises JEN's depreciation approach
- *Depreciation method* – describes the depreciation method used by JEN to develop its forecast regulatory depreciation
- *Standard and remaining asset lives* – explains that JEN proposes to retain its existing asset lives
- *Forecast regulatory depreciation* – sets out JEN's depreciation schedule based on the regulatory asset lives.

11.1 Summary

JEN has adopted a straight line depreciation method (on an inflation-adjusted asset base) for the forthcoming regulatory control period. JEN has used this depreciation method in the current and previous regulatory control periods. It is also the default method adopted by the AER for the PTRM.

JEN considers that a straight line depreciation method is consistent with clause 6.5.5(b)(i) of the Rules across all asset classes.

JEN adopts the same asset classes as prescribed by the ESC.

For each asset category, the standard life is the weighted average of the standard lives of the asset classes in that category, where the class lives are those JEN uses for engineering design purposes.

Forecast regulatory depreciation over the forthcoming regulatory control period is shown in Table 11-1.

Table 11-1: Forecast regulatory depreciation over the forthcoming regulatory control period

Details, 2010 $m	2011	2012	2013	2014	2015	Total
Straight line depreciation	45.9	53.0	60.1	60.8	59.8	279.8

Details, 2010 $m	2011	2012	2013	2014	2015	Total
Inflation on opening RAB	18.2	20.3	22.3	23.9	25.2	109.9
Regulatory depreciation	**27.7**	**32.7**	**37.9**	**36.9**	**34.7**	**169.9**

11.2 Depreciation method

JEN proposes to adopt a straight line depreciation method (on an inflation-adjusted asset base) for the forthcoming regulatory control period, consistent with previous regulatory control periods and the AER's PTRM.

Straight line depreciation on an inflation-adjusted asset base results in depreciation being back-ended in nominal terms. This profile is more consistent with user expectations and increasing network utilisation than alternatives such as declining balance or historic cost straight line.

11.3 Standard and remaining asset lives

JEN has adopted the standard and remaining asset lives set out in Table 11-2 for the forthcoming regulatory control period.

Table 11-2: Standard and remaining asset lives adopted for the forthcoming regulatory control period

Asset class	Standard life (years)	Average remaining life (years)
System assets		
Sub-transmission	47.3	29.1
Distribution system assets	46.8	21.0
Standard metering	NA	4.4
Public lighting	NA	8.3
SCADA/Network control	30.5	30.5
Non-system assets		
Non-network general assets - IT	5.0	3.2
Non-network general assets - Other	18.9	15.5

Notes: Standard life is not applicable for standard metering and public lighting assets because there is no new capital expenditure for these assets (they are alternative control services).

For each asset category, the standard life is the weighted average of the standard lives of the asset classes in that category, where the class lives are those that JEN uses for engineering design purposes. Remaining lives (at the start of the forthcoming regulatory period) are calculated in the regulatory model as remaining asset value divided by annual depreciation.

JEN notes that, for assets that will be replace in the forthcoming regulatory period, it may be appropriate for accelerated depreciation to apply, such that those assets are written off by the end of the forthcoming regulatory control period—reflecting the fact that the economic life of those assets comes to an end once the assets no longer exist. JEN has chosen not to apply this approach at this stage, to reduce price shocks to customers. JEN reserves the right to revisit this approach, should the AER's draft determination indicate allowable revenues that are below the cash-flows required by JEN to undertake its proposed work program.

11.4 Forecast regulatory depreciation

Applying the principles and asset lives described in the preceding sections, JEN's forecast regulatory depreciation over the forthcoming regulatory control period is shown in Table 11-1.

12 Return on capital, inflation and taxation

This chapter set outs how JEN has calculated its proposed return on capital, its estimated cost of corporate tax and its proposed method that is likely to result in the best estimates of inflation used in the derivation of the building block revenue for the forthcoming regulatory control period. It satisfies the requirements of Rules 6.4.3(2), 6.5.2, and Schedule 6.1.3(9), and also RIN clauses 8.1 and 8.2.

This chapter is structured as follows:

- *Summary* - summarises JEN's proposed cost of capital, inflation and taxation allowance over the forthcoming regulatory control period
- *Background* – provides background on the ESC's 2005 decision on real vanilla cost of capital of 5.90 per cent using a Sharpe-Lintner capital asset pricing model (**CAPM)** and taxation allowance
- *Averaging period* – outlines JEN's proposed approach to averaging period
- *Return on capital and inflation* – explains how JEN has derived its return on capital and inflation assumptions consistent with the Rules
- *Taxation allowance* – explains how JEN has calculated its taxation allowance over the forthcoming regulatory control period.

12.1 Summary

For the purpose of the forthcoming regulatory control period, JEN has assessed the prevailing market conditions affecting its cost of capital and tax allowance. This has included examination of the relevant requirements of the Rules, the RIN, the AER's Statement of Regulatory Intent on WACC (**SORI**)[38], the AER's final decision on Weighted Average Cost of Capital (**WACC**)[39] and well accepted methods for estimating the cost of capital for assets with JEN's risk profile.

JEN proposes a nominal vanilla WACC of 10.86 per cent and a value of imputation credits (**gamma**) of 0.20 for the forthcoming regulatory control period, in accordance with clause 6.5.2 of the Rules.

JEN considers that the proposed cost of capital reflects the risks of an efficient electricity distributor, in compliance with the Rules.

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[38] AER, *Electricity Transmission and Distribution Network Service Providers Statement of Regulatory Intent on the Revised WACC Parameters (Distribution)*, May 2009.

[39] AER, *Electricity Transmission and Distribution Network Service Providers Review of the Weighted Average Cost of Capital (WACC) Parameters, Final Decision*, May 2009.

Table 12-1 summarises JEN's estimated cost of corporate income tax.

Table 12-1: Forecast tax cost of corporate income tax over the forthcoming regulatory control period

	2011	2012	2013	2014	2015	Total
Cost of corporate income tax	12.2	7.3	8.9	8.9	8.9	46.3

12.2 Averaging period

This section outlines JEN's proposed approach to the averaging period. JEN proposes to use this period to estimate the yields on 10 year Commonwealth Government bonds and 10 year BBB+ rated corporate bonds.

Under clause S6.1.3(8) of the Rules, JEN must propose the commencement and length of the period for the purposes of calculating the nominal risk free rate under clause 6.5.2(c)(2) of the Rules. Confidential section 12.2.1 below includes JEN's proposed averaging period in days and the commencement date. In accordance with clause 6.5.2(c)(iii) of the Rules, JEN requests that this appendix be kept confidential.

For the purpose of this regulatory proposal, JEN uses a 15 business day averaging period commencing on 1 October 2009 and ending on 21 October 2009 to estimate the proposed rate of return at the time of lodging this proposal, but recognises that these estimates will require updating for the final measurement period agreed with the AER.

Commercial in Confidence

12.3 Return on capital and inflation

The cost of capital aims to compensate JEN's debt and equity holders for the opportunity cost of lending/investing their funds in the JEN network. The Rules require that JEN calculate a return on capital for each regulatory year by applying a rate of return for that regulatory control period to the value of the regulatory asset base as at the beginning of the regulatory year. The Rules set out the formula used to calculate the WACC.

Table 12-3 summarises JEN's proposed WACC parameters as well as resulting WACC variants.

Table 12-3: JEN's proposed WACC Parameters

Parameters	JEN Proposal
Inflation (i)	2.47%
Nominal risk free rate (R_f^n)	5.47%
Real risk free rate	2.93%
Debt margin (D^n)	4.71%
Nominal pre-tax cost of debt	10.18%
Real pre-tax cost of debt	7.52%
Market risk premium (MRP^n)	8.00%
Equity beta (β_e)	0.80
Post-tax nominal return on equity	11.87%
Gearing (D/V)	60%
Dividend imputation (γ)	0.20
Corporate tax rate (T_c)	30%
Nominal vanilla WACC	10.86%
Real vanilla WACC	8.18%

Notes:

1. Real costs of debt and equity and the risk free rate are calculated from the nominal equivalents using the Fisher equation and forecast inflation.

2. Debt margin is based on an efficient electricity business with a BBB+ credit rating.

Each parameter is discussed below along with the regulatory information requirements.

12.3.1 Inflation

JEN proposes an inflation forecast of 2.47 per cent. The forecast inflation is the geometric average of the forecast annual inflation for each of the ten years from 2010 to 2019 as follows:

Table 12-4: Forecast Inflation

Details	2010	2011	2012	2013	2014	2015	2016-2019
Inflation forecast	2.00 %	2.25 %	2.50 %	2.50 %	2.50 %	2.50 %	2.50 %
Geometric average	2.47 %						

Notes:

- Inflation forecasts are for the year to December.
- For the 2010 and 2011, the expected inflation outcomes are as stated in the Reserve Bank of Australia's (RBA's) most recent Statement on Monetary Policy[40].
- For the 2012 to 2019, the expected inflation outcomes are the midpoint of the RBA's long term inflation target range[41]. The range is 2 per cent to 3 per cent, with the midpoint 2.50 per cent.

This approach is consistent with the AER's approach in the recent price determinations for NSW and ACT electricity distributors.

12.3.2 Gearing

JEN proposes a gearing ratio of 60 per cent, consistent with the SORI.

12.3.3 Nominal risk free rate

The nominal risk free rate is 5.47 per cent, based on the 15-day historical average of the annualised yield on 10 year Commonwealth Government Securities (**CGS**) to 21 October 2009 using the indicative mid rates published by the RBA.

JEN estimates the yield on a 10 year CGS maturing at the 15 business days to 21 October 2019 by interpolating on a straight-line basis the yields on the CGS bonds maturing at 15 March 2019 and 15 April 2020. This method is consistent with the SORI.

40 Reserve Bank of Australia, *Statement on Monetary Policy*, 6 November 2009, p. 72.

41 Ibid.

12.3.4 Market risk premium

JEN proposes a market risk premium of 8.00 per cent, which differs from the SORI, but is consistent with current market conditions.

Background: Recap of AER's decision to adopt an MRP value of 6.5%

The AER's final decision on WACC sets out the following reasoning as the basis for the adoption of an MRP value of 6.5% as follows[42]:

As the AER is maintaining a 10-year term for the risk-free rate, for internal consistency, the term of the MRP should also be 10 years. As the NER require the AER to have regard to the need for the rate of return to be forward looking, it is a 10 year forward looking perspective that is therefore of relevance.

The NER also require the AER to have regard to the need for the rate of return to be commensurate with prevailing conditions in the market for funds. However, these two requirements are not competing, but rather, when read together, are a requirement to have regard to the need for the MRP to reflect the prevailing expectations of a 10 year MRP, as at the relevant point in time, with that point in time being at the time of the reset determination (rather than at the time of the WACC review). Notwithstanding this statement, the AER has taken into account current financial conditions (at the time of this WACC review) to the extent that these conditions are expected to prevail over the period to which the outcomes of this WACC review apply. Accordingly, the AER should determine each parameter, including the MRP, in such a way as it is relevant for a 10 year perspective from the commencement of the next regulatory control period for each service provider affected by this review.

The WACC final decision proceeds to state that the MRP should be a value that reflects the forward looking long term MRP.

The AER's conclusions are set out as follows[43]:

The AER considers that prior to the onset of the global financial crisis, an estimate of 6 per cent was the best estimate of a forward looking long term MRP, and accordingly, under relatively stable market conditions—assuming no structural break has occurred in the market—this would remain the AER's view as to the best estimate of the forward looking long term MRP.

However, relatively stable market conditions do not currently exist and taking into account the uncertainty surrounding the global economic crisis, the AER considers two possible scenarios may explain current market conditions:

- that the prevailing medium term MRP is above the long term MRP, but will return to the long term MRP over time, or

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42 AER, *Electricity Transmission and Distribution Network Service Providers Review of the Weighted Average Cost of Capital (WACC) Parameters, Final Decision*, May 2009, p. 235.

43 Ibid, p.238.

- that there has been a structural break in the MRP and the forward looking long term MRP (and consequently also the prevailing) MRP is above the long term MRP that previously prevailed.

Whilst it cannot be known which of these scenarios explain current financial conditions, both are possible, and both suggest a MRP above 6 per cent at this time may be reasonable. However, having regard to the desirability of regulatory certainty and stability, the AER does not consider that the weight of evidence suggests a MRP significantly above 6 per cent should be set.

Accordingly, the AER considers that a MRP of 6.5 per cent is reasonable, at this time, and is an estimate of a forward looking long term MRP commensurate with the conditions in the market for funds that are likely to prevail at the time of the reset determinations to which this review applies.

Notably, on page 237 of the WACC final decision, the AER acknowledges that:

Cash flow based measures currently indicate a forward looking MRP well above 6 per cent, however up until 2008 these measures consistently indicated a forward looking MRP well below 6 per cent.

Overview of persuasive evidence to depart from the value set out in the SORI

Clause 6.5.2(g) of the Rules states that:

A distribution determination to which a statement of regulatory intent is applicable must be consistent with the statement unless there is persuasive evidence justifying a departure, in the particular case, from a value, method or credit rating level set in the statement.

Clause 6.5.2(h)(2) provides that in deciding whether a departure from a value, method or credit rating level set in a statement of regulatory intent is justified in a distribution determination, the AER must consider:

whether, in the light of the underlying criteria, a material change in circumstances since the date of the statement, or any other relevant factor, now makes a value, method or credit rating level set in the statement inappropriate.

JEN considers that there is persuasive evidence available now that demonstrates that a value of 6.5 per cent for the MRP is inappropriate and that in the particular case of the forthcoming determination for JEN, departure from the 6.5 per cent MRP value specified in the SORI is justified. An overview of this evidence is set out below.

Yield based indicators suggest that the current cost of raising new equity is now well above that implied by the 6.5 per cent MRP value set in the SORI.

As noted above, the WACC final decision acknowledged that the Rules require the AER to set a rate of return that is forward-looking and which reflects prevailing market conditions. The AER noted that:

- Each WACC parameter, including the MRP, must be set in such a way as it is relevant for a 10 year perspective (consistent with the term of the risk-free rate) from the commencement of the next regulatory control period for each service provider affected by the WACC review, and

- For parameters, such as the MRP, a difficulty arises, since the Rules require the AER to lock-in either a value or methodology, but in the case of the MRP (which does vary over time according to economic conditions) there is no adequate method of automatically updating the MRP at the time of each reset determination.

A clear risk arising from the locking-in of a value for the MRP at each WACC review, particularly when market conditions are highly uncertain, is that this value may change materially at the time of a reset determination, such that it no longer supports a forward-looking rate of return at that time. There is, therefore, a degree of tension between the requirement to lock-in a value for the MRP at the WACC review and the requirement to have regard to the need for the rate of return to reflect forward-looking expectations commensurate with prevailing conditions at the time of each reset determination.

The WACC final decision acknowledged this tension:

If the MRP varies over time, then by definition, the locking in of a value may not always completely reflect forward looking expectations prevailing at the time of each reset determination. Accordingly, for some reset determinations the actual (unobservable) MRP may be somewhat above this value, though for other reset determinations the actual (unobservable) MRP maybe be somewhat below.[44]

JEN's forthcoming regulatory control period commences on 1 January 2011, a period that is 13 months away. While there has been emerging evidence of a recovery in economic conditions in the Australian market in recent months, JEN considers that it would be extremely premature to suggest that the market cost of equity has returned to levels that preceded the global financial crisis.

Some authoritative commentators have noted recently that there is a significant risk of a "double dip recession". For instance, on an ABC radio program broadcast on 7 August 2009, Dr Adrian Blundell-Wignall (the deputy director of financial and enterprise affairs at the OECD) stated that the global financial crisis is far from over and the world faces a serious risk of another credit crunch and a double dip recession.[45]

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[44] Ibid, p. 191.

[45] Stephen Long, *World at risk of 'double dip recession'*, 7 August 2009. See http://www.abc.net.au/news/stories/2009/08/07/2649723.htm and http://www.abc.net.au/pm/content/2008/s2649677.htm

Similarly, in an editorial piece published on 30 October 2009, Peter Schiff (President of US firm Euro Pacific Capital) commented that:

In the end, this stimulus, just like prior doses, will only worsen the condition it is meant to cure. When it wears off, the resulting recession will be even bigger than the one that everyone assumes has just ended.

In an editorial piece by Nouriel Roubini (Professor of Economics at New York University's Stern School of Business) published in The Financial Times[46] on 23 August 2009 commented that:

In summary, the recovery is likely to be anaemic and below trend in advanced economies and there is a big risk of a double-dip recession.

In a similar vein, page 3 of the Reserve Bank's August 2009 Statement notes that significant uncertainty remains regarding the economic outlook, with the possibility that the recovery since the March 2009 quarter may be short-lived:

Given the rapidly evolving international financial and economic conditions, the outlook for the Australian economy continues to be subject to considerable uncertainty, although the risks are more balanced than they have been for some time. With confidence globally still fragile, it remains possible that the outlook could again weaken.

In the WACC final decision the AER acknowledged that the additional uncertainty associated with the global financial crisis justified an increase in the MRP above the value prescribed in the Rules.

The prevailing market outlook supports the view that any sustained improvement in market conditions is still highly uncertain and a return to pre-crisis conditions is some considerable way off.

Given this outlook, JEN believes that at the time the AER makes its forthcoming determination, it is likely that the return on equity required by investors in the market will reflect a level of risk aversion which exceeds that reflected in the value allowed for the MRP in the SORI[47].

Indeed, market evidence recently compiled by the Financial Investor Group (**FIG**) on the cost faced by Australian listed companies with regulated network assets in raising new equity in the current environment (as implied in dividend yields) supports the view that investors are currently expecting a (pre-tax) return on equity in the range of 15 per cent to 18 per cent[48]. By contrast, using a risk free rate of

46 http://www.ft.com/cms/s/0/90227fdc-900d-11de-bc59-00144feabdc0.html

47 Assuming the equity beta is kept constant at the value allowed in the SORI.

48 The Financial Investor Group, *Supplementary Submission to the ERA regarding its Draft Decision on Western Power's Proposed Revisions to the Access Arrangement for the South West Interconnected Network*, 22 October 2009, p. 6.

5.5 per cent, a corporate tax rate of 30 per cent and the SORI values for the MRP and equity beta implies a pre-tax return on equity of 15.2 percent, which is at the bottom end of the range required by the market.

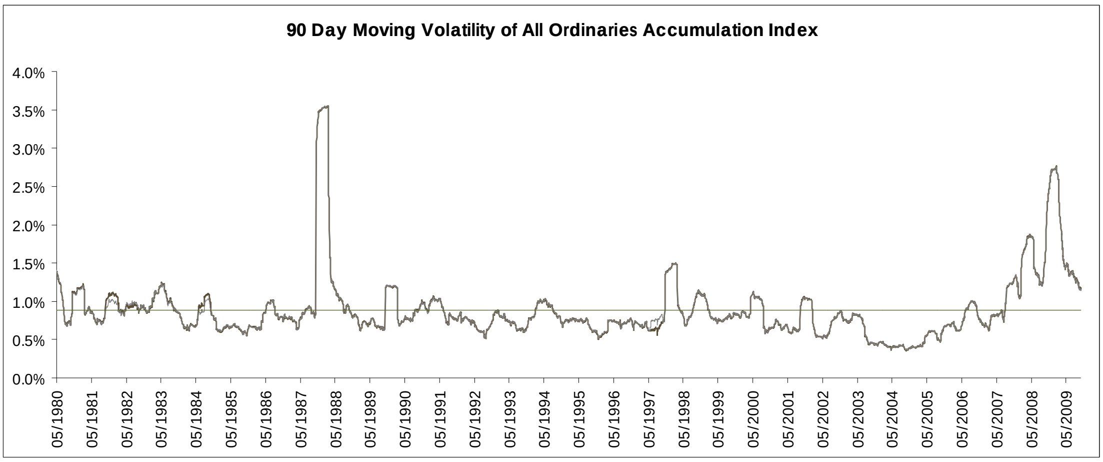
JEN notes that setting an appropriate cost of capital must ultimately be guided by the requirements of investors, noting that the long term interests of consumers will not be served if inadequately low levels of network investment are caused by the regulator setting an inadequate allowance for the WACC. Failure to allow regulated businesses a reasonable opportunity to earn a return which is consistent with that expected by investors will mean that capital will be diverted to other investment opportunities where capital, which is currently expensive and scarce, can be more productively employed.

JEN considers that the ongoing uncertainty regarding the outlook for the global economy and capital markets, coupled with the available evidence on the cost of equity faced presently by regulated utilities, provide persuasive evidence that demonstrates that a value of 6.5% for the MRP is inappropriate and that in the particular case of the forthcoming determination for JEN, departure from that value is justified.

Equity and debt markets have, over recent months, and are still, exhibiting an unusual period of high risk relative to historical norms. The chart below which has been extracted from a study by Dr. Stephen Bishop and Professor Robert Officer of Value Adviser Associates, captures this through the volatility trend in the ASX All Ordinaries Accumulation Index since 1980.

Figure 12-1: Volatility of Stock Market

Source: Dr. Bishop, S and Professor R. Officer (Value Adviser Associates), Market Risk Premium,



Estimate for 2011-2015, October 2009 (Bishop and Officer (2009).

JEN considers that the unique environment within which the AER is undertaking its review of JEN's regulatory proposal justifies a departure, in this particular case, from the MRP value specified in the SORI. In particular, the ongoing uncertainty regarding the global capital market outlook and the impact of this uncertainty on investors' required returns, coupled with the new evidence presented herein, constitute relevant factors (pursuant to clause 6.5.4(h)(2)) that justify a departure from the MRP value in the SORI. JEN's view is supported by the following conclusions of Bishop and Officer, which are set out in their report dated October 2009 (a copy of which is provided in Appendix 7.10):

The "MRP" will change over time to reflect the "market's" view of the risk and attitudes to risk. A positive risk premium exists because future return outcomes are not known. We doubt whether the distribution of premiums is constant over time. Consequently we do not believe that a constant MRP reflecting the long term average is appropriate under current economic circumstances in particular.

In the past we have recommended the use of the long term average historical MRP. This is not because we believe it to be stable over time but because there has been neither a well developed theory to predict and explain changes nor has there been a supportable empirical base for moving away from the long term average.

Three factors have combined to change this departure from our prior recommendations to use a long term average MRP to reflect a forward MRP:

A period of unusual economic circumstances in the form of the global financial crisis;

The availability of a forward view of market risk though the implied volatility of options on the stock market index;

Promising research guiding the time period of departures from the norm.

While still an evolving area for research we are of the view that advances to date and the recent events in the economy warrant a departure from the use of the long term average."[49]

Bishop and Officer proceed to state that:

- their estimate of the current forward-looking MRP is 12.0 per cent per annum
- their best estimate of the MRP over the regulatory period (January 2011 - December 2015) is in the range of 7 to 10.6 per cent per annum, and
- they recommend adopting an MRP of 8.0 per cent for the regulatory period.

These recommendations were made with reference to the forward view of volatility implicit in the pricing of options on the ASX 200 index, and the current high spreads in yields on corporate debt. In relation to their implied volatility analysis, Bishop and Officer:

[49] Dr. S Bishop and Professor R Officer (Value Adviser Associates), *Market Risk Premium, Estimate for 2011-2015*, October 2009.

- develop a measure of implied volatility based on the S&P/ASX 200 index options with a three month horizon

- demonstrate that there is a sufficiently strong relationship between their measure of the implied volatility of the stock market and realised volatility, as well as between realised volatility and realised market return, and

- apply the required rate of return per unit of risk implied from the relationship between realised volatility and realised market return[50], to the measure of implied volatility to derive a forward-looking MRP.

Based on this analysis, Bishop and Officer estimate that the implied MRP is currently 12.2 per cent per annum, which is substantially above the long term historical average MRP of 7.0 per cent per annum.[51]. However, they acknowledge that the MRP is not stationary and changes over time. Further analysis conducted by Bishop and Officer, and set out in their report, led them to recommend an MRP of 8.0 per cent over the 2011-2015 regulatory period.

Bishop and Officer also analysed spreads on bond yields to derive a forward view of the MRP. As there is some degree of consistency between spreads on corporate bonds and the risk premium required by equity investors, the observed corporate bond spreads can provide a good indicator of the likely required equity market returns. Analysing BBB-rated seven year corporate bonds, Bishop and Officer note that current spreads are at elevated levels and substantially above historical levels. Their analysis confirms that there is a high degree of consistency between their implied stock market volatility measure and the spread on BBB-rated seven year corporate bonds, which is currently at elevated levels.

In a similar vein, it is noted that an examination of the relativity between the required rates of return on debt and equity as implied in the SORI also provides new evidence that the rate of return on equity is currently understated.

Based on prevailing yields on 10 year Commonwealth Government Securities (5.5 per cent), the implied post-tax nominal cost of equity, using the values in the SORI for the MRP and equity beta, is approximately 10.7 per cent. By contrast, the credit spreads for 10 year BBB+ debt, as estimated by Bloomberg, currently indicate that the required post-tax nominal return on 10 year BBB+ rated debt is around 9.3 per cent. This implies, using the current SORI values, that shareholders would be willing to invest for a rate of return that is only 140 basis points higher than the rate at which financiers are willing to provide fixed rate BBB+ rated 10 year debt.

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50 The analysis necessarily requires the use of constant required rate of return per unit of risk. Bishop and Officer (2009) estimate this rate to be about 50 basis points.

51 Bishop and Officer, 2009, p. 10.

This result seems anomalous, particularly given the substantially higher levels of risk that equity holders bear relative to debt providers. Furthermore, the relative historical risk premiums between debt and equity investment in the Australian market do not support this result.

JEN considers that the information and analysis set out above, and in the report of Bishop and Officer, provides persuasive evidence that demonstrates that a value of 6.5 per cent for the MRP is inappropriate, and that, in the particular case of the forthcoming determination for JEN, a departure from the 6.5 per cent MRP value specified in the SORI is justified. JEN's proposed MRP is set out below.

JEN's proposed MRP

As noted above, the AER is required to provide JEN with a rate of return which is set to appropriately reflect market conditions at the time of its determination. The new evidence provided in this regulatory proposal indicates that the SORI value for the MRP significantly understates the MRP that is likely to prevail over the forthcoming regulatory period. Therefore, if it were to be applied to set JEN's cost of capital over the forthcoming regulatory period, there would be insufficient incentives for efficient investment in electricity distribution infrastructure over the period, and this would be contrary to the long term interests of consumers and hence the National Electricity Objective.

JEN considers that there is a strong case for the AER to depart from the SORI value for the MRP for this particular determination, given:

- the on-going uncertainty regarding the outlook for global economic and capital market conditions in the context of the global financial crisis

- the new evidence presented regarding investors' forward-looking required rates of return in the present environment of on-going high uncertainty, and

- JEN's contention that under these circumstances, applying the MRP value specified in the SORI would deliver an outcome that is inconsistent with the National Electricity Objective and the Revenue and Pricing Principles set out in the National Electricity Law.

JEN considers that the matters noted above are relevant factors (pursuant to clause 6.5.4(h)(2) of the Rules) that justify, in this particular case a departure from the MRP value specified in the SORI.

Based on the evidence presented in this Proposal and the appended report of Bishop and Officer, JEN considers that there is persuasive evidence to adopt a value for the MRP of 8 per cent for the purpose of the AER's determination for the forthcoming regulatory period.

12.3.5 Equity Beta

JEN proposes an equity beta of 0.80, consistent with the SORI.

12.3.6 Debt margin

JEN proposes a debt margin of 4.71 per cent. This margin is added to the nominal risk free rate of 5.47 per cent to give JEN's proposed cost of debt of 10.18 per cent.

The SORI stipulates that the debt margin be determined as follows:

- the observed annualised Australian benchmark corporate bond rate used in the calculation is to relate to corporate bonds with a term to maturity of 10 years

- the debt risk premium over the risk free rate is to be estimated with reference to a bond with a BBB+ credit rating.

The AER's illustrative calculations in the final decision on WACC estimate this debt margin using benchmark fair value yields issued by Bloomberg.

JEN notes that Bloomberg no longer issues the fair value yields used as data for illustrative calculations in the AER's final decision on WACC by the AER. Accordingly, JEN proposes an alternative method to using Bloomberg fair value yields for estimating a debt premium that is consistent with the SORI, is commensurate with prevailing market conditions and is supported by publicly available market data.

JEN proposes a three-step method to estimating the debt premium based on expert advice from PwC—see Appendix 7.10. The Victorian electricity distributors commissioned PwC to:

- propose a method to test whether the Bloomberg fair value curves that the AER has relied on in previous determinations reasonably meets the legislative requirements

- propose an alternative method for calculating the debt risk premium that best meets the legislative requirements should Bloomberg fail the above test

- apply the Bloomberg test and, if necessary, the alternative method during the first 15 business days in October 2009.

Based on PwC's advice, JEN proposes the following three steps.

Step one: test quality of Bloomberg fair value yields

Since the onset of the recent financial crisis, Bloomberg fair value yield curves have arguably underestimated the fair value yield of BBB+ rated bonds. This unreliability was driven by Bloomberg using unreliable bank feeds, judgement in estimating generic bond yields and excluding select bonds when estimating fair value yields.

JEN understands that there are recent signs that the reliability of the Bloomberg fair value curves has improved. But in the future, JEN proposes that Bloomberg data must satisfy a set of tests before being used to estimate the fair value yield on BBB+ rated bonds

PwC proposes three tests for Bloomberg data:

1. Does the coefficient of variation of bank feeds into Bloomberg for the Australian corporate bonds of greater than three years duration that are considered for Bloomberg's fair value curve exceed 0.05?

2. Does the average value of the difference between Bloomberg's generic yield (**BGN**) and the mean of bank feeds for the Australian corporate bonds used to construct Bloomberg's fair value curve, expressed as a percentage of the Bloomberg generic yield, exceed +/- 2.50 per cent?

3. Does the average value of the difference between Bloomberg's BGN and the corresponding point on the Bloomberg fair value curve, expressed as a percentage of the BGN, exceed +/- 4.00?

Step two: adjust data if Bloomberg fair value yields fail tests

If the Bloomberg fair value yields fail the tests, PwC proposes a hierarchy of actions to determine a debt risk premium.

Step three: estimate debt premium

PwC proposes to estimate the yield on 10 year BBB rated bonds by extrapolating on a linear basis the yields on five and seven year BBB rated bonds. Here, the debt margin on 10 year bonds is calculated as follows:

$$\text{DebtMargin}_{10yr} = \frac{\text{DebtMargin}_{7yr} - \text{DebtMargin}_{5yr}}{2/3} + \text{DebtMargin}_{7yr} .$$

PwC applied the three-step method to the first 15 business days in October 2009 and concluded that the Bloomberg fair value curve reasonably meets the legislative requirements. Over this period, PwC estimate a debt premium of 4.71 per cent on BBB+ rated bonds as follows:

Table 12-5: JEN's proposed debt premium

Details	Average Yield / Margin
Yield on five year BBB rated bonds	9.18 %
Yield on five year CGS	5.35 %
Debt margin on five year BBB rated bonds	3.83 %
Yield on seven year BBB rated bonds	9.57 %
Yield on seven year CGS	5.39 %
Debt margin on seven year BBB rated bonds	4.18 %
Proposed debt margin on 10 year BBB rated bonds	4.71 %

JEN recognises that its proposed debt margin will require updating for the final measurement period agreed with the AER. On this basis, JEN submits the method contained in Appendix 7.10 for approval.

12.4 Taxation allowance

JEN calculated its tax building block using the PTRM, which is updated to use the ESC's method of tax depreciation. JEN also proposes a gamma of 0.2 that reflects a fair market value of imputation. This is JEN's a departure from the parameters specified in the AER's Statement of Regulatory Intent.

Table 12-6 shows JEN's forecast tax liability, value of imputation credits and tax building block for the forthcoming regulatory control period.

Table 12-6: Forecast taxation allowance over the forthcoming regulatory control period

	2011	2012	2013	2014	2015	Total
Taxable income	15.3	9.1	11.1	11.2	11.1	57.9
Value of imputation credits	3.1	1.8	2.2	2.2	2.2	11.6
Cost of corporate income tax	**12.2**	**7.3**	**8.9**	**8.9**	**8.9**	**46.3**

The value of imputation credits and JEN's tax asset base as at 1 January 2011 are discussed below.

12.4.1 Dividend imputation

JEN proposes a value of imputation credits (or gamma) of 0.2, which is a departure from the 0.65 contained within the SORI. JEN considers there is persuasive evidence that justifies the departure in accordance with clauses 6.5.4(g) and 6.5.4(h) of the Rules.

Gamma is the subject of much debate between regulators and regulated businesses. It is JEN's strongly held view that the best and most credible evidence and analysis supports a value for gamma of zero.

Gamma is the market value of the imputation credits that are created by a firm, and is the product of the assumed proportion of the credits created that are distributed to investors (the payout ratio **F**) and the market value of imputation credits once in the hands of investors (**theta**). In its final decision on WACC, the AER adopts an assumed payout ratio of one. This assumption is discussed further below.

JEN considers that dividend drop-off studies are the most reliable and accurate method for estimating theta, but recognises that the AER also relies on tax statistics to estimate a value of 0.65 in its final WACC decision.

Dividend drop-off studies

SFG Consulting (**SFG**) recently quantified the value of theta between 0.2 and 0.35 using a dividend drop-off study.[52] Even if a payout ratio of one is assumed (see below), these results suggest a gamma of less than 0.5.

JEN considers that the SFG study is more comprehensive than the 2006 Beggs and Skeel study[53] that the AER relied on in its final decision on WACC[54] because the SFG results are based on:

- a much larger cross section of firms; and
- a more recent data period.

Moreover, after correcting for perceived deficiencies in the SFG study, the AER found that the study suggests a theta of between -0.23 and 0.47.[55] Again assuming

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52 SFG Consulting, *Market practice in relation to franking credits and WACC: Response to AER proposed revision of WACC parameters*, Report prepared for ENA, APIA, and Grid Australia, 1 February 2009.

53 D. Beggs and C. L. Skeels, *Market arbitrage of cash dividends and franking credits,* The Economic Record, volume 82, number 258, September 2006, p. 247.

54 AER, *Electricity Transmission and Distribution Network Service Providers Review of the Weighted Average Cost of Capital (WACC) Parameters, Final Decision*, May 2009, p. 400 footnote 794.

55 AER, *Electricity Transmission and Distribution Network Service Providers Review of the Weighted Average Cost of Capital (WACC) Parameters, Final Decision*, May 2009, p. 400, footnote 794 and p. 441 footnote 1081.

a payout ratio of one, these results suggest a gamma of less than 0.5 and certainly less than 0.65.

Subsequent to the AER's final WACC decision, the Victorian and South Australian electricity distributors commissioned an independent review by Associate Professor Skeels of the SFG study and associated comments within the AER's final WACC decision (**the Skeels review**).[56]

During his review, Associate Professor Skeels sought further information addressing the perceived deficiencies of the SFG study and based on this information concluded the SFG theta estimate of 0.23 is the most accurate estimate currently available for Australia. Moreover, Associate Professor Skeels reasons that:

> It is clear that the more recent data used in the SFG results presented in Appendix 1 favour an estimate of theta that is lower than that of 0.57 which was obtained by Beggs and Skeels on the basis of less recent data. However, it might be argued that the minor methodological differences that remain between the method of Beggs and Skeels (2006) and that of SFG bias their estimate of theta downwards. (This is not a position to which I subscribe and I present it only in the garb of a devil's advocate.) Were such a position to be taken then, in my opinion, a compelling case can be made that the empirical evidence overwhelmingly supports the notion that the true value of theta lies between the SFG estimate of 0.23 and the Beggs and Skeels (2006) estimate of 0.57, and that in all probability it lies closer to 0.23 than 0.57. [57]

Associate Professor Skeels also concludes that:

- the SFG study adopts an analytical approach that is consistent with the regression-based methodologies favoured by the AER
- because it uses more recent data and a larger amount of data, the SFG study provides a more accurate estimate of theta than the Beggs and Skeels study—a study that he co-authored and was relied upon by the AER in its final WACC decision to determine the lower bound for theta of 0.57

JEN considers that the Skeels review presents new evidence that was not considered by the AER in reaching its final WACC decision and that supports an estimate of theta of 0.23 as the best available dividend drop-off study.

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[56] This review was commissioned by the Victorian and South Australian electricity distributors through Gilbert and Tobin. See attachments in Appendix 7.10 for the data relied upon by Associate Professor Skeels.

[57] Christopher L Skeels, *A Review of the SFG Dividend Drop-Off Study*, A report prepared for Gilbert and Tobin, 28 August 2009, p 5.

Tax statistics

JEN considers that taxation statistics do not provide an accurate estimate of the value of imputation credits. These statistics measure the quantum of corporate taxation, the amount of credits distributed and the amount of credits claimed.

But the amount of credits claimed is not the value of those credits. Shareholders bear risk when earning the dividends and imputation credits, and must wait before they are distributed. Necessarily, shareholders discount the value of these credits for risk and the time value of money—a process that tax statistics do not capture.

Synergies Economic Consulting (**Synergies**) has undertaken new research using tax statistics from the ATO covering the period 2003 to 2007. This study observed that the payout ratio over this period was between 58 per cent and 77 per cent—with an average of 66 per cent. This average is largely consistent with the findings of Hathaway and Officer that estimates the payout ratio at 0.71,[58] but is significantly different from the payout ratio of 1 assumed by the AER in the electricity WACC decision.

A payout ratio of 0.66 is also consistent with the views of Peter Fero—tax partner at Gilbert & Tobin—and Robert Officer who both independently reject the assumption that all imputation credits are eventually distributed to shareholders. In his recent opinion,[59] Mr. Fero concludes that income tax law presents significant impediments to full effective distribution of imputation credits. Similarly, in a recent review for ETSA,[60] Officer points to empirical evidence that shows that the distribution rate is significantly lower than one. Both views are inconsistent with the 100 per cent distribution rate assumed by the AER in its final WACC decision.

JEN considers that the best estimate of the payout ratio is 0.66 based on the Synergies study because it uses recent observable data and is consistent with the views of Peter Fero and Officer.

The Synergies study also estimates that investors on average only utilise 35 per cent of the credits that they receive, which means that the maximum possible value for theta is 0.35 if a payout ratio of 1 is assumed, or 0.23 if the average observed payout ratio of 0.66 is assumed instead.[61] Synergies highlight that the lowest feasible value for gamma is zero, which is JEN's view of the most appropriate value for gamma.

[58] N. Hathaway and B. Officer, *The Value of Imputation Tax Credits – Update 2004*, Capital Research Pty Ltd, November 2004, pp.13 and 24.

[59] Peter Feros, *Review of WACC parameters: Gamma*, ETSA Price Reset, 22 June 2009.

[60] Robert R. Officer, *Estimating the Distribution Rate of Imputation Tax Credits: Questions Raised by ETSA's Advisers*, 23 June 2009.

[61] Synergies Economic Consulting, *Gamma: New Analysis Using Tax Statistics*, 28 May 2009, p. 6.

JEN considers that the Synergies study sets an upper bound for gamma of 0.23 based on a payout ratio of 0.66.[62] This upper bound is consistent with

- the findings of the SFG study, which estimates a gamma range of between 0.13 and 0.23 if a payout ratio of 0.66 is used
- the findings of the Skeels review, which estimates a gamma of 0.15 if a payout ratio of 0.66 is also used.

Proposal

For the purpose of this proposal, JEN proposes a gamma range of 0 to 0.23, relying on the Synergies study and the Skeels review to set the upper end of this range and the theoretical argument that gamma is zero to set the lower end. JEN proposes a gamma of 0.2 from this range.

Based on the new evidence discussed above, JEN considers that the AER's conclusions in the electricity WACC decision about the value of imputation credits in the hands of investors and the payout ratio are incorrect and do not meet the requirements of the Rules.

JEN is not alone in its view that gamma is below 0.65. IPART recently confirmed this view in a review of the cost of capital in light of the AER's final WACC decision.[63] Here, IPART noted that it was "not convinced that there is conclusive evidence underpinning the values adopted by the AER for the payout ratio and theta" and concluded that a gamma less than 0.65 was more appropriate.[64] JEN considers that this view reinforces its proposal to depart from the SORI.

12.4.2 Opening tax asset value at 1 January 2011

Consistent with rule 11.17.2, JEN proposes rolling forward its TAB from 1 January 2005 to 31 December 2010 using the method determined by the ESC in the 2005 EDPR. The results, summarised by regulatory year, are in Table 12-7:

Table 12-7: Roll forward of TAB from 2005 to 2010

	2005	2006	2007	2008	2009	2010
Opening TAB 1 January	315.2	328.0	348.8	372.1	377.2	399.4
Capital Expenditure	49.0	64.0	70.3	50.9	64.9	104.6
Disposals	1.0	0.5	0.5	1.2	0.0	0.1

62 Synergies Economic Consulting, *Gamma: New Analysis Using Tax Statistics*, 28 May 2009, p. 8.

63 AER, *Electricity Transmission and Distribution Network Service Providers Review of the Weighted Average Cost of Capital (WACC) Parameters, Final Decision*, May 2009.

64 IPART, 11 November 2009, p 61 to 62.

	2005	2006	2007	2008	2009	2010
Depreciation	35.2	42.8	46.4	44.6	42.7	45.4
Closing TAB 31 December	**328.0**	**348.8**	**372.1**	**377.2**	**399.4**	**458.5**

Table 12-8 shows the closing 2010 balance by tax asset class:

Table 12-8: Roll forward of TAB from 2005 to 2010

	TAB 1 January 2005	Gross capital expenditure	Disposals	Depreciation	TAB 31 December 2010
Demand related capex	87.3	183.6	1.5	27.7	241.6
Replacement expenditure (group 1)	0.0	76.4	0.7	69.4	6.3
Replacement expenditure (group 2)	6.6	8.3	0.1	4.0	10.8
Replacement expenditure (group 3)	3.4	7.4	0.1	1.2	9.5
Environment, safety & legal	6.5	35.6	0.2	9.2	32.6
Standard metering (group 1)	5.9	4.8	0.0	10.0	0.7
Standard metering (group 2)	0.0	0.0	0.0	0.0	0.0
SCADA/Network control	1.1	3.0	0.0	1.2	2.9
Non-network general assets – IT	7.1	47.1	0.0	39.4	14.8
Non-network general assets – IT	7.3	37.6	0.7	14.1	30.0
Land	20.4			0.0	20.4
6.7 to 10 years	0.0			0.0	0.0
10 to 13 years	1.9			1.5	0.3
13 to 30 years	2.5			1.9	0.7
> 30 years	165.3			77.4	87.8
Total	**315.2**	**403.7**	**3.4**	**257.0**	**458.5**

13 Revenue requirements for standard control services

This chapter provides an overview of the completed PTRM and JEN's total revenue requirements, in compliance with clauses 6.3, 6.4, 6.5.9 and Schedule 6.1.3(6) of the Rules. It summarises the building block components of JEN's proposed revenue requirements over the forthcoming regulatory control period and the resulting X factors to achieve JEN's revenue requirements.

This chapter is structured as follows:

- *Summary* - provides an overview of JEN's revenue requirement for standard control services over the forthcoming regulatory control period
- *Annual revenue requirements* – sets out JEN's revenue requirements over the forthcoming regulatory control period
- *X factors for standard control services* – provides the resulting X factors for JEN's standard control services to achieve its revenue requirements

13.1 Summary

JEN has determined its required annual revenues to average $211.9 million over the forthcoming regulatory control period using the building block costing method required by the Rules and specified by the AER in its F&A Paper and its PTRM.

JEN has sought to smooth the recovery of its required revenues over the period by adopting a price path that aligns the NPV of JEN's required and expected revenues whilst:

- aligning the final year revenues with the building block for that year to minimise future price shocks
- adopting a common X factor for 2012 to 2015 to minimise price volatility.

Table 13-1 shows JEN's summary revenue requirements over the forthcoming regulatory control period.

Table 13-1: JEN summary revenue requirements over the forthcoming regulatory control period

	2011	2012	2013	2014	2015	NPV
Building block revenue requirement	201.4	202.3	222.0	216.9	217.0	839.1
Smooth revenue requirement to achieve NPV neutral outcome	208.7	208.6	209.0	212.3	219.1	839.1
X factors	-39.6%	-3.0%	-3.0%	-3.0%	-3.0%	

13.2 Annual revenue requirements

The Rules require that the revenue requirement for each year of the forthcoming regulatory control period is calculated as the sum of the return on capital, return of capital, operating and maintenance expenditure and corporate tax allowance.

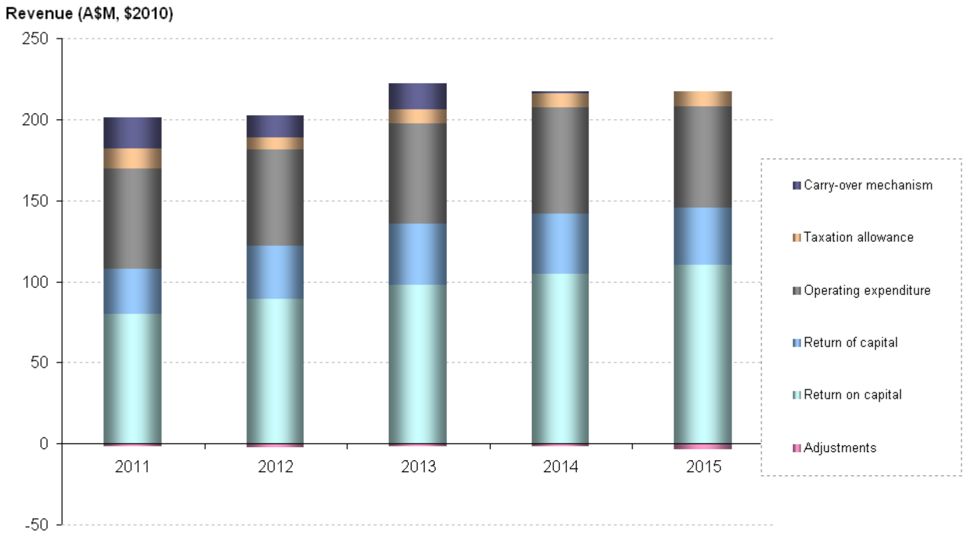
JEN's revenue requirement over the forthcoming control period as per the AER's PTRM (see Appendix 5) is shown in Table 13-2. The revenue building block components have been described in chapters 8 to 12.

Table 13-2: JEN building block revenue requirements over the forthcoming regulatory control period

	2011	2012	2013	2014	2015	Total	NPV
Return on capital	80.1	89.1	97.9	104.9	110.5	482.5	378.6
Return of capital	27.7	32.7	37.9	36.9	34.7	169.9	133.8
Operating expenditure	62.6	61.1	62.9	66.7	66.1	319.4	253.1
Taxation allowance	12.2	7.3	8.9	8.9	8.9	46.3	37.1
Carry-over mechanism	19.6	13.6	15.7	0.7	0.0	49.7	42.7
Adjustments	-0.9	-1.7	-1.2	-1.2	-3.2	-8.2	-6.3
Building block revenue requirement	201.4	202.3	222.0	217.0	217.0	1,059.6	839.1

Table 13-2 shows that JEN's unsmoothed revenue requirements increase from $201.4 million in 2011 to $217.0 million in 2015. The revenue requirements from the AER's PTRM are shown diagrammatically in Figure 13-1 below.

Figure 13-1: Forecast building blocks for the forthcoming regulatory control period



Note: For illustrative purposes, the adjustments are offset against the operating expenditure building block.

Building block adjustments

Table 13-2 includes adjustments for schemes operating under the current regulatory control period. These are:

- true-up of the former S factor incentive mechanisms as required by the AER's F&A Paper and discussed in section 16.3
- the EBSS specified by the ESC and discussed in chapter 17
- true-up for differences between estimated and actual capex in the final years of the previous regulatory control period
- the capital overspend recovery mechanism specified by the ESC and discussed in section 18.3.

13.3 X factors for standard control services

The revenue requirements calculated in accordance with the Rules must be smoothed to determine X factors in accordance with the requirements of Schedule 6.1.3(6) of the Rules. The smoothing mechanism adopted is the weighted average price method as per the AER's PTRM. Under this method JEN has used the 2010 distribution use of system (**DUOS**) prices submitted to the AER on 4 November 2009 as the base year prices. The PTRM then adjusts these tariff components during the forthcoming regulatory control period and calculates the X factors based on NIEIR's forecasted quantities per tariff component

Table 13-3: X factors over the forthcoming regulatory control period

per cent	2011	2012	2013	2014	2015
X factors	-39.6%	-3.0%	-3.0%	-3.0%	-3.0%

The above X factors result in real average distribution price increases over the period. While JEN's regulatory proposal sets out the expenditures, programs and projects required to deliver the service standards in an efficient and sustainable manner, an increase in expenditures is required over the forthcoming regulatory control period, which will result in a corresponding increase in average network prices.

The X factor smoothing proposed by JEN satisfies the requirements of clause 6.5.9(b)(2) and (3) of the Rules in that it meets the following criteria:

- the maximum allowed revenue requirement aligns to the NPV of the annual building block revenue requirement
- the expected maximum allowed revenue for the last regulatory year is as close as reasonably possible to the annual building block revenue requirement for that year.

14 Price control mechanisms

This chapter complies with clauses 6.2.5 and 6.2.6 of the Rules, and sets out JEN's response and relevant considerations relating to the AER's F&A Paper on the price control mechanisms that apply to JEN's standard control distribution services, alternative control services and recovery of transmission use of system (**TUOS**) services costs.

This chapter is structured as follows:

- *Summary* - provides an overview of JEN's response and relevant considerations relating to the AER's F&A Paper on the price control mechanism
- *Standard control services* – sets out JEN's comments on the weighted average price cap (**WAPC**) the AER proposes to apply to these services
- *Alternative control services* – sets out JEN's comments on the price cap the AER proposes to apply to these services
- *TUOS services* – sets out JEN's comments on the WAPC that currently applies to the pass through of these costs and amendments required to accommodate the Victorian photovoltaic feed in tariff (**PFIT**) regime.

14.1 Summary

In response to the AER's price control mechanism:

- JEN has developed X factors that give effect to the WAPC and price cap that the AER has specified for standard control services and alternative control services respectively
- JEN interprets the AER's F&A Paper to mean that the WAPC parameters for standard control services have the definitions currently defined in the ESC's Electricity Distribution Price Review 2006-10 Final Decision Volume 2 Price Determination as amended for the appeal (ESC Price Determination) for prescribed distribution services
- the definition of the S factor parameter in the standard control services WAPC must be amended from its current specification to accommodate the introduction of the new STPIS arrangements
- the definition of payments to embedded generators in the maximum transmission revenue formula must include rebates made and administrative costs incurred by JEN under the Victorian PFIT regime.

14.2 Standard control services

The AER's F&A Paper sets out the standard control services WAPC formula as follows:

$$\frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} \times q_{t-2}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ij} \times q_{t-2}^{ij}} \leq (1+CPI_t)\times(1-X_t)\times(1+S_t)\times(1+L_t)$$

This formula provides a different variant on the former WAPC applied by the ESC. The difference is the inclusion of the S factor '(1+St)' and the L factor '(1+Lt)' instead of the ESC approach of including a single St and Lt factor. The L and S factors are discussed further below.

14.2.1 L factor

JEN believes that the AER's approach does not achieve an outcome that materially different to that of the ESC because the effect of the '(1+' element of the AER formula was previously implemented through the ESC's specification of St and Lt. However, a consequence of this difference is that the previous Lt specification set out in clause 2.3.15 of the ESC Price Determination cannot be adopted in its current form.

The AER's F&A Paper states that:

'The AER will carryover any adjustments arising from the EDPR, for example in relation to "L" and "S" factor adjustments, that will impact in the 2011–15 regulatory period.' [65]

In order to do this in a manner that reflects the Lt factor adjustments that distributors are entitled to, JEN proposes that the AER either:

- reverts to the previous ESC WAPC formula and Lt factor specification; or
- adopts the Lt specification that corrects for the AER's proposed transition and ensures distributors receive the cost recovery intended by the ESC formula that applied during the current regulatory control period when these costs were incurred.

This is a transitional issue which if not addressed will affect JEN's revenue recovery but not its service performance.

[65] AER, *Final framework and approach paper for Victorian electricity distribution regulation*, May 2009, p.75.

14.2.2 S factor

An equivalent issue arises for the specification of the STPIS adjustment factor St. The AER has published certain component parts of its STPIS but as yet has not published a comprehensive S factor specification capable of inclusion in the WAPC.

An important element of the proposed St specification is the 2012 adjustment for actual 2010 service performance outcomes. As discussed in chapter 16, to implement the AER's required true-up of the ESC's current service incentive scheme JEN has had to estimate its 2010 performance outcomes. To avoid any windfall gains or losses arising from this, JEN proposes a once off correction formula be applied in 2012 prices. This formula is set out in chapter 16.

Further, because the AER has required a one-off true-up for the existing ESC service incentive scheme, the St factor must be set to:

- zero in 2011 and 2012 if the AER retains its proposed WAPC specification
- one if the existing ESC WAPC specification is retained.

14.3 Alternative control services

The AER's F&A Paper sets out the alternative control services price cap formula to apply to individual service prices as follows:

$$p_t \leq p_{t-1} \times (1 + CPI_t) \times (1 - X)$$

Chapter 19 sets out that JEN's proposed pricing of alternative control services seeks to align the costs of these services with their prices at any given point in time. To achieve this outcome within the AER's proposed price cap approach, JEN has set its X factor to reflect the weighted input cost escalation for these services.

This price path method best ensures JEN's prices for alternative control services continue to reflect the actual cost in any given year and reduced JEN's cost recovery risk due to volume forecast error.

14.4 TUOS services

Under rule 6.18.7 of the Rules, JEN will recover the costs of TUOS services on a pass through basis. This is consistent with the arrangements currently in place under chapter 3 of the ESC Price Determination.

14.4.1 Revenue control

JEN proposes to retain the TUOS revenue control from the ESC's Price Determination adjusted for PFIT recovery in each year of the forthcoming regulatory control period as a means of:

- complying with rule 6.18.7
- preserving consistency of treatment
- avoiding any cost recovery risk from varying these arrangement which have a three-year recovery and true-up cycle that cannot be easily altered without generating risk of windfall loss or gain.

The specification of this formula is set out in clause 3.3 of the ESC Price Determination.

Consistent with previous treatment, JEN proposes that this revenue control applies in an uninterrupted fashion as JEN transitions into the forthcoming regulatory period. This is necessary to ensure recovery of TUOS costs JEN has incurred to date and will continue to incur during the price review process and which its recovery and true-up arrangements are currently scheduled to continue into the forthcoming regulatory control period.

14.4.2 Premium solar feed in tariff

On 1 November 2009 the Victorian PFIT amendment to the Electricity Industry Amendment Act 2009 came into effect. Under this scheme, households, community groups and small businesses with small-scale solar PV systems (up to 5 kilowatt capacity), and consuming up to 100 megawatt hours a year, will receive a rebate of 60 cents per kilowatt hour for the electricity they feed back into JEN's network.

The amendment requires JEN to pay this PFIT rebate to applicable customers and allows JEN to recover the associated costs.

JEN proposes to define the PFIT rebate costs as a recoverable payment under the maximum transmission revenue control in clause 3.3 of the ESC Price Determination.

This recovery requires a new factor in the maximum transmission revenue formula. The definition of the new factor should include:

- the systems enhancement and administration costs that JEN incurs to implement the PFIT scheme
- ongoing PFIT administration costs

- rebates paid to customers under the PFIT scheme.

15 Pass through events

This chapter complies with clause 6.6 and S6.1.3(2) of the Rules, and with RIN clause 7 by providing details of JEN's proposed additional pass through events and associated materiality thresholds.

This chapter is structured as follows:

- *Summary* - provides an overview of JEN's proposed cost pass through events and associated materiality thresholds
- *Proposed pass through events* – describes and explains the proposed additional pass through events for which JEN may recover (or repay) costs if the event occurs during the forthcoming regulatory control period
- *No alternative recovery mechanism* – explains why the costs of the proposed pass through events would not be covered by any of the prescribed pass through events in the Rules, or recoverable by any other means
- *Materiality threshold* – sets out and explains the proposed materiality threshold for each proposed pass through event before recovery (repayment) of costs will occur.

15.1 Summary

In addition to those listed in the Rules, JEN proposes the following pass through events for its distribution determination:

- emissions trading scheme (**ETS**) event
- financial failure of a retailer event
- declared retailer of last resort (**ROLR**) event
- insurer credit risk event
- insurance event
- asbestos compensation event
- force majeure event.

JEN proposes a materiality threshold of $1 million for each of these pass through events. This threshold would apply to a single event or to a number of incremental events in the same pass through category occurring in the same regulatory year.

This would be a symmetrical materiality threshold applicable to both positive and negative change events for events that are subject to such a threshold.

JEN proposes to retain the existing arrangements under the ESC's final determination for the materiality thresholds for existing pass through events which are financial failure of a retailer and declared RoLR event.

15.2 Proposed pass through events

Table 15-1 identifies the proposed pass through events. JEN has assessed the circumstances in which each of the proposed pass through events is likely to arise and considers that the probability of these events occurring and/or the impact that these events may have on JEN's costs is too uncertain to reasonably forecast in JEN's forecast revenue requirement. It is therefore appropriate to manage the risks associated with those events by allowing JEN to recover (or requiring it to repay) any material changes in costs by way of a pass through if, and only if, the relevant event occurs.

Table 15-1: Proposed pass through events

Item	Description	Reasons
Emissions trading scheme (ETS) event	The introduction of an ETS (including without limitation the CPRS), which has the effect of materially increasing or decreasing JEN's costs of providing direct control services.	The costs associated with an ETS will not be within JEN's control, and there is still significant uncertainty as to the final form, timing and extent - and therefore cost - of such a scheme.
Financial failure of a retailer event	The liquidation or administration of a retailer, as a consequence of which JEN does not receive revenue to which it was otherwise entitled for the provision of direct control services.	This is a pass through event under the ESC's final determination for the current regulatory control period. The ESC's 2006-7 decision on credit support arrangements currently restricts the amount of credit support that JEN may require from a retailer under a use of system agreement. Under the ESC's formula many retailers provide no, or minimal, credit support. The ESC recognised the increased risk of this approach for distributors, and made its decision on the basis that it would allow distributors to pass through any costs they may incur as a result of the distributor having inadequate security in the event of a retailer insolvency. The pass through would apply to unrecovered charges in excess of the

Item	Description	Reasons
		amount of credit support held by JEN for that retailer.
Declared retailer of last resort (ROLR) event	An event whereby an existing retailer for distribution customers is unable to continue to supply electricity, its customers are transferred to the declared retailer of last resort, and as a result JEN incurs materially higher or lower costs in providing direct control services than it would have incurred but for that event.	This is a pass through event under the ESC's final determination for the current regulatory control period. A ROLR event would trigger procedures that pass a cost on to JEN, including administrative costs from transferring the customers of a failed retailer to the retailer of last resort within a short time period. The costs associated with a ROLR event are largely out of JEN's control
Insurer credit risk	The insolvency of the nominated insurers of SPI Australia (Assets) Pty Limited (SPIAA), as a result of which JEN: • incurs materially higher or lower costs for insurance premiums than those allowed for in the distribution determination; or • in respect of a claim for a risk that would have been insured by SPIAA's insurers, is subject to a materially higher or lower claim limit or a materially higher or lower deductible than would have applied under that policy.	SPIAA holds insurance on behalf of JEN. This risk is uncontrollable and unforeseeable and the event would be likely to have a material impact on JEN's costs. The Marsh Self Insurance Risk Quantification Report notes that the probability of this event occurring is low due to the insurance company's strong credit rating, but the potential cost impact is material if the risk eventuates.
Insurance event	An event that is covered by an insurance policy applicable to JEN, but in respect of which the loss materially exceeds the policy limit, and as a result JEN must bear the amount of that excess loss. For the purposes of this pass through event, the relevant policy limit is the greater of the actual limit from time to	JEN has obtained prudent and efficient insurance cover commensurate with a prudent assessment of its business risk. The probability of claims exceeding the limit of cover is low, but the costs associated with an above limit insurance claim event cannot be adequately forecast. The approach to policy limits ensures that the pass through amount would not be increased by any subsequent change of cover.

Item	Description	Reasons
	time and the limit under JEN's insurance cover at the time of making this regulatory proposal.	
Asbestos compensation event	A successful claim for compensation made against JEN for damages resulting from exposure to asbestos on JEN's property.	JEN is aware of the existence of asbestos materials within particular substations and within the roofing of its Broadmeadows site. The Marsh Self Insurance Risk Quantification Report notes that, should asbestos become unstable, there may be potentially fatal and costly consequences. This event is uncontrollable and unforeseeable.
Force majeure event	An event that is outside JEN's reasonable control and for which: • the occurrence and/or timing is unpredictable; • no cost allowance has been made in the distribution determination; • insurance is (or has become) unavailable or is only available at a cost that would not be efficient for a prudent distributor; and • no other category of pass through event would apply, as a result of which JEN incurs materially higher or lower costs in providing direct control services than it would have incurred but for that event.	This would cover events such as (but not limited to) fire, flood, cyclone, storm, earthquake, riot or sabotage. These events are uncontrollable, unpredictable in timing and extent, and the cost impact is potentially material.

15.3 No alternative recovery mechanism

JEN considers that each of the proposed pass through events is different in definition and scope from the pass through events defined in the Rules, as outlined below:

- A regulatory change event is defined by reference to the meaning of 'regulatory obligation or requirement' in the NEL, which covers obligations imposed under the NEL, the Rules and other instruments of a specified type or nature. Importantly, this pass through event:
  - requires a change in a relevant obligation, and would not apply where an existing regulatory obligation is activated (for example a retailer of last resort obligation)
  - requires that the change substantially affects the manner in which direct control services are provided, and would not apply where services can continue to be provided in the same manner, but only at increased cost (as would be likely in relation to the introduction of the CPRS).
- A service standard event is limited to changes in the nature, scope, standards or other manner in which direct control services are provided. None of JEN's proposed additional pass through events relates to such an event.
- A tax change event relates to the imposition, removal or change of a relevant tax. None of JEN's proposed additional pass through events relates to a tax.
- A terrorism event relates to an act done for political, religious, ideological or ethnic purposes or reasons. Although the proposed force majeure pass through event could in theory include acts of terrorism, JEN has proposed that the force majeure pass through would expressly exclude events that fall within another pass through category.

The costs associated with the pass through events proposed above are not expected to be recoverable through any other mechanism. Specifically, those costs:

- are not insurable or could only be insured at a cost that is not justifiable due to the unpredictable nature of the risk
- are not recoverable through any jurisdictional schemes or mechanisms
- cannot be recovered from any contracting party.

15.4 Materiality threshold

The factors taken into account in determining JEN's proposed materiality threshold are:

- the value of the excess on insurance policies in place for the JEN network

- the materiality threshold determined by the ESC for the current regulatory control period for existing pass through events

- the materiality threshold determined by the AER in the NSW and ACT distribution determinations.

The excess on insurance policies currently in place for the JEN network is $100,000 per event, or $500,000 for multiple events. The materiality threshold imposed by the AER for the NSW and ACT electricity networks was 1 per cent of annual revenues (approximately $2 million if applied to JEN).

The pricing principles contained in section 7A of the NEL provide that "a regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs". JEN does not consider that a pass through threshold of greater than $500,000 would allow JEN to recover at least the efficient costs that it has incurred. However, given that the AER has previously determined a materiality threshold of 1 per cent of annual revenue, JEN proposes that the materiality threshold for the forthcoming regulatory control period be fixed between the value of JEN’s insurance excess and the value of the materiality threshold that results from the application the 1 per cent of annual revenue threshold imposed for the NSW and ACT electricity networks.

Accordingly, JEN proposes a materiality threshold of $1.0 million for each new category of pass through event. This threshold would apply to a single event or to a number of incremental events in the same pass through category occurring in the same regulatory year. This value is appropriate as it represents the maximum cost that JEN is in a position to absorb in relation to a single pass through event or a series of related pass through events

JEN proposes that this be a symmetrical materiality threshold which would apply to both positive and negative change events.

16 Service target performance incentive scheme (STPIS)

This chapter sets out how JEN proposes that the STPIS should apply for the forthcoming regulatory control period. It builds upon the AER's proposed STPIS arrangements and the AER's inherent assessment therein of compliance with clauses 6.6.2 and S6.1.3.4 of the Rules, also clauses 6.3.2(a)(3), 6.4.3(a)(5), 6.4.3(b)(5), 6.5.6(e)(8) and 6.5.7(e)(8). JEN has also provided information in compliance with RIN clauses 1.2(a) and 1.3.

The chapter is structured as follows:

- *Summary* – provides an overview of JEN's STPIS proposal and its responses and relevant considerations relating to the AER's proposed STPIS
- *The AER's service target performance incentive scheme (STIPS)* – discusses the AER's proposed STIPS and what modifications JEN has proposed
- *S factor true-up* – details how JEN has given effect to the AER's requirement to true-up the financial consequences of the ESC's service incentive scheme (S factor) that has applied during the current regulatory control period.

16.1 Summary

In summary:

- JEN proposes to adopt the AER's proposed STPIS largely as specified by the AER[66] including for target setting as detailed in section 7.2.
- JEN has proposed specific arrangements to address issues of error or inappropriate incentives within the AER's proposed STPIS relating to:
  - measurement of MAIFI
  - the formula for incorporating the STPIS into annual allowed price movements
  - the calculation of the major event day boundary

[66] AER, *Proposed Electricity distribution network service providers, Service target performance incentive scheme*, Version 01.2, 21 September 2009.

- – Guaranteed Service Level (**GSL**) for failure to give four days notice of a planned outage.

- JEN has prepared a true-up for the financial consequences of the ESC's to-be-discontinued S factor scheme.

16.2 AER's STPIS

JEN proposes to adopt the STPIS based on the AER's proposed STPIS dated September 2009 as amended for the following points:

- MAIFI definition
- the formula for incorporating the STPIS into annual allowed price movements
- the calculation of the major event days boundary
- GSL target for failure to give four days notice of a planned outage.

16.2.1 MAIFI definition

The major reliability metrics proposed by the AER are already measured within the current S factor scheme. While JEN does not propose additional measures relating to reliability, the definition of MAIFI in the AER STPIS does not match that currently in use in Victoria. JEN proposes MAIFI be defined as a MAIFI event, or MAIFIe, as currently applied in Victoria.

Additionally, the AER's definition of a momentary event is currently set as an incident lasting less than 1 minute. JEN considers that this event definition should be modified from a 1 minute period to 5 minutes. This will:

- better support developments in future self-healing networks so that remote re-configuration of the network can be further encouraged given the relaxation in time duration
- align the event definition with the IEEE standard
- allow current MAIFI performance data to form the basis of the targets by ensuring future performance is measured on a comparable basis.

Currently, in accordance with the ESC's specifications for measuring momentary outages and interruptions,[67] Victorian DNSPs treat one sequence as one interruption for the purposes of measuring MAIFI (also referred to as event MAIFI or MAIFIe). This approach is also consistent with the IEEE standard 1366.

The effect of the AER's proposed change would be to potentially double MAIFI for a single event. If this were to occur, targets would also have to be adjusted to ensure a like with like comparison.

Self healing networks

The AER's proposed definition would discourage distributors from applying fast protection (through reclosing) to reduce the probability of sustained secondary damage resulting from transient faults, which are especially common in rural areas.

In rural areas, it is not uncommon for a protection device, such as an automatic circuit re-closer (**ACR**), to be set up with a reclose sequence lasting less than one minute, but comprising multiple recloses in one sequence. In practice:

- a reclose is often successful after two recloses within a single reclose sequence
- the customer is unlikely to notice the difference between a single reclose or a single sequence comprising multiple recloses.

Definition alignment with IEEE standard and current Victorian practice

In the current and earlier regulatory periods, the Victorian DNSPs have reported, and been rewarded and penalised against MAIFIe based on the IEEE 1366-2003 standard. This defines a momentary interruption event as:

> " 3.15 momentary interruption event: An interruption of duration limited to the period required to restore service by an interrupting device. Note - Such switching operations must be completed within a specified time of 5 min or less. This definition includes all reclosing operations that occur within five minutes of the first interruption. For example, if a recloser or circuit breaker operates two, three, or four times and then holds (within 5 min of the first operation), those momentary interruptions shall be considered one momentary interruption event."

Notably, the Victorian approach is different to that in the AER's proposed STPIS. Appendix A of the STPIS document defines MAIFI as:

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[67] ESC, *Information Specification (Service Performance) for Victorian Electricity Distributors*, June 2008, p. 27-28.

MAIFI (Momentary Average Interruption Frequency Index): The total number of customer interruptions of one minute or less, divided by the total number of distribution customers. Notes: No.4 – In calculating MAIFI, each operation of an automatic reclose device is counted as a separate interruption. Sustained interruptions which occur when a recloser locks out after several attempts to reclose should be deleted from MAIFI calculations.

The difference between MAIFI and MAIFIe is best explained with the following two scenarios of a temporary fault:

- in scenario 1, a fault occurs on the network at time-point A, whereby the feeder circuit breaker operates to remove supply. After a period of a few seconds, the feeder circuit breaker attempts to restore supply at time-point B, and finds that the original fault remains and therefore operates again. Finally, the feeder circuit breaker attempts to restore supply again at time point C and finds that the original fault has gone from the network and therefore supply is permanently restored. The entire sequence occurs in a time period that is less than 1 minute. For scenario 1, under the status quo approach, MAIFIe would count as 1 event. Yet under the AER's definition, a DNSP would be forced to report a MAIFI of 2 incidents, as supply was lost twice within a few seconds

- by comparison (scenario 2), if the feeder circuit breaker unsuccessfully attempted to restore supply at time-point B and went to lockout, the customer still experiences loss of supply twice, but the measure of SAIFI would be reported as 1 event only, as per MAIFIe in the example above.

JEN, as well as other Victorian distributors, have always reported MAIFIe to the ESC and, therefore, the historical performance upon which the targets for the forthcoming regulatory control period will be set does not reflect (and underestimates) the MAIFI figures that would have resulted if the AER definition of MAIFI had applied.

Setting targets based on one metric (MAIFIe) and measuring actual performance for the STPIS using a different metric (MAIFI) will see a perceived degradation of performance, as many incidents where only 1 event was reported previously will suddenly be reported as 2 or more events.

Industry experience to date has confirmed that generally the success of reclose operation is higher when a multi-shot reclose function is implemented (and where it is safe to do so, for example, in rural areas during non-bushfire season). The use of MAIFI (as opposed to MAIFIe) is likely to discourage a distributor from implementing multi-shot reclose function, resulting in lower reliability of supply to customers.

MAIFIe data is the only data available upon which the AER can reasonably based future targets. The use of MAIFIe is more closely aligned with customers' experience of the interruption—a key reason for the current use of MAIFIe in Victoria. Also, the adoption of MAIFIe for Victorian DNSPs will ensure continuity and comparability of reliability performance from the beginning of calendar year 2000.

There is another drawback in using MAIFI instead of MAIFIe. Failure to adopt MAIFIe as the reliability performance measure will unfairly characterise those DNSPs that deploy smart network technologies, such as distribution automation and self healing networks (automatic supply restoration), as DNSPs with abnormally high MAIFI and render the MAIFI measure meaningless for comparative purposes.

JEN therefore proposes a definition of MAIFI consistent with the current definition of MAIFIe.

16.2.2 Incorporating STPIS into JEN's prices

The AER's proposed formula for incorporating the STPIS into annual allowed price movements under s weighted average price cap contains errors. These errors relate to:

- the summation specification for tariff components states 'n' instead of 'm'
- the quantities being specified as t-1 instead of t-2
- the prices being specified as pt+1 for the numerator and pt for the denominator instead of pt for the numerator and pt-1 for the denominator.

The correct formula, notwithstanding JEN's comments in chapter 14, is the formula presented in Appendix F of the AER's F&A Paper. The AER's F&A Paper sets out the standard control services WAPC formula as follows:

$$\frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} \times q_{t-2}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ij} \times q_{t-2}^{ij}} \leq (1+CPI_t)\times(1-X_t)\times(1+S_t)\times(1+L_t)$$

16.2.3 The calculation of the major event day boundary

The AER's proposed STPIS sets service performance targets on a fixed basis for the forthcoming regulatory control period based on the average performance over the past five years (2005 to 2009). In contrast, the AER's proposed calculation of exclusion events or major event days (T_{MED}) will vary over the period based on actual outcomes during that period. This presents an unacceptable and unwarranted risk to DNSPs because the targets they will be assessed against are fixed, but the manner in which their performance will be measures is not.

Clause 2.5(c) of the STIPS document states the term T_{MED} will be calculated and approved annually by the AER in accordance with appendix C.

The AER has asked the DNSPs to demonstrate in their regulatory proposals that the investment proposal will achieve the reliability targets set for the forthcoming regulatory control period.

As reliability targets for the forthcoming regulatory control period are set (and fixed) using the T_{MED} (determined from 5 years of historical performance), JEN believes that an annual reassessment of T_{MED} using a rolling five-year average has the potential to expose the DNSP to a changing T_{MED}, with a resultant risk of not achieving the reliability targets. It creates risks that DNSPs cannot be expected to efficiently manage because major event days are, by their nature, uncontrollable.

JEN therefore proposes that T_{MED} should be fixed for the duration of the forthcoming regulatory control period.

16.2.4 GSL for failure to give four days notice of planned outages

The AER's proposed STPIS introduces a new GSL that requires the distributor to make a payment of $50 if the distributor fails to provide a customer with at least four days notice of planned interruptions.

JEN notes that, while distributors currently have the obligation to notify customers of planned interruptions (and JEN has processes in place to ensure compliance with this obligation), the requirement has never involved verifying whether the notification has been received by the customer.

JEN currently notifies customers of planned interruptions through card drops in customers' letter boxes. The cards are dropped by JEN's contractors and are not mailed. JEN therefore does not keep records that verify whether a particular customer has been notified. With the implementation of the proposed new GSL, issues could arise where a customer claims not to have received the notification card.

JEN notes that, if this GSL is implemented, JEN will need to incur additional costs to implement a new system for notifying customers of planned interruptions and confirming receipt of the notification.

JEN considers that the costs of such a system outweigh the benefits of adding this GSL requirement and are likely to also outweigh customers' willingness to pay for such a system. On this basis JEN proposes to not include this particular GSL.

Should the AER not accept JEN's proposal, JEN reserves the right to submit a revised regulatory proposal including an additional opex cost item to recover the cost of a new system to track customer notifications.

16.2.5 Summary of reasons for departure from AER's proposed STPIS

As noted above, JEN has adopted the STPIS largely as specified by the AER. JEN has identified above the four areas of departure from the AER's proposed STPIS. In accordance with RIN clause 1.3, Table 16-1 summarises the reasons for departure, how these departures align with the STPIS objectives and the effects of the departures.

Table 16-1: STPIS departures summary of reasons and effects

Departure	Reason	STPIS objective alignment	Effects on STPIS
MAIFI definition	Alignment with historic treatment and IEEE standard Allows historic performance to inform targets as intended by the STPIS	Ensures the target and measure continue to deliver service improvements and are not affected by measurement changes Avoids perverse incentive regarding self-healing network infrastructure	Alignment of targets and performance measurement with current practice and IEEE standards
The formula for incorporating the STPIS into annual allowed price movements	STPIS formula is incorrect and does not reflect the AER's published weighted average price cap	Ensures accurate incorporation of STPIS incentives in allowed annual price movements	Ensures accurate incorporation of STPIS incentives in allowed annual price movements
The calculation of the major event day boundary	Fixed targets with variable exclusion criteria generated inefficient and unwarranted risk for DNSPs	STPIS should only reward and penalise DNSPs for service performance outcomes that are (1) within their control and (2) sufficiently valued by customers	Aligns target setting with performance measurement
Four day planned outage notification GSL	Cost of implementation will outweigh the benefits	JEN will continue to comply with its notification obligations without incurring additional	Reduced GSL items by one

Departure	Reason	STPIS objective alignment	Effects on STPIS
		costs to implement a potentially unwarranted GSL	

16.3 S factor true-up

The AER's F&A Paper (page 95) stated that:

> 'the AER notes that benefits and penalties accrued in the current regulatory control period under the ESCV scheme will not be incorporated in the price cap formula. Rather, financial carryover amounts from the current regulatory control period will be included as a building block element in the calculation of allowed revenue for the forthcoming regulatory control period.'

The true-up must take the financial consequences of the ESC's S factor regime that are yet to transpire and convert these into a building block cost item. Absent the true-up, the S factor would not reward/penalise for 2009 and 2010 performance until 2011 and 2012 prices respectively. Further the t-6 adjustment to 'back-out' S factor rewards and penalties associated with performance in the last two regulatory periods (which have been subject to the ESC's S factor) would not be completed until 2017.

This means the true-up must assess all these S factor increments and decrements by year and turn them into a present value for inclusion in JEN 2011-15 building blocks revenue requirement.

16.3.1 True-up approach

The AER has provided no guidance for how the true-up of the ESC's S factor will apply. It has simply required a true-up that takes the financial consequences of the ESC's S factor regime that are yet to transpire and converts these into a building block cost item.

JEN has developed a method that:

- assesses all the anticipated S factor increments and decrements by year over the 2011 to 2018 period
- turns these into a present value for inclusion in JEN 2011-15 building blocks revenue requirement.

Identifying the S factor increments and decrements over the 2011 to 2017 period required JEN to determine what revenue stream these should apply to in order to establish the required building block adjustments.

JEN investigated two methods:

4. adjusting revenue streams and applicable incentive rates for the Po and X factors

5. rolling forward 2010 revenues for CPI and weighted average growth in order to avoid the need for Po and X factor adjustment.

JEN considers the latter method to be preferable as it avoids the need for JEN to iterate between the true-up calculation and the Po and X factors. This significantly simplifies the calculation without diminishing the accuracy of the true-up computation.

JEN has provided the calculations underpinning its true-up in the S-factor sheet of the amended PTRM (confidential Appendix 3). Table 16-2 sets out the true-up amounts for inclusion in JEN's building block revenue requirement. The 2015 value represents the present value as at 2015 of the increments and decrements applicable in 2015, 2016 and 2017.

Table 16-2: JEN S factor true-up amounts

Details 2010 $m	2011	2012	2013	2014	2015	Total
True-up amounts	-3.9	-1.6	-1.2	-1.1	-2.9	-10.6

16.3.2 Actual 2010 performance correction

The true-up requires JEN to estimate actual 2010 service performance which will not be known in time for the AER determination. To mitigate any risks associated with this, JEN proposes a correction formula to apply to 2012 prices for differences between estimated and actual 2010 performance.

This formula is set out below and is designed to ensure that no windfall gains or losses arise from the transition to the AER's STPIS scheme and required S factor true-up.

$$SFTUCF = 1 + \frac{PV(Change\ in\ true-up\ \ for\ 2012\ to\ 2015)}{PV(Forecast\ \mathrm{Re}venue\ \ for\ 2012\ to\ 2015)}$$

Explanation of correction formula

The 'true up' for the S factor amounts attributable to periods prior to the 2011 to 2015 regulatory period will not be able to factor in the amount attributable to year 2010 performance. This is because 2010 performance will not be known at the time of the determination. Given this, the ‘true up’ will need to be based upon a forecast of year 2010 performance. The option then exists to correct for the difference between the forecast and actual performance in 2010 once that information becomes available.

JEN considers that such a correction is justified given the volatility in service performance attributable to environmental factors and the unnecessary risk this would impose. Such a correction would also be consistent with the intent of the ESC’s scheme in that it would relate the reward or penalty to the known (rather than forecast) performance.

JEN considers that the simplest means of correcting for the difference between forecast and outturn service performance in 2010 would be to add a correction factor to the price control applying to year 2012 prices (that is, the first year after information for 2010 is available). This correction factor as defined below would take the form of a one-off adjustment to the level of prices for the remainder of the regulatory period (that is, the level of prices for 2012 to 2015), and hence an adjustment to the price control would only be required for 2012 (with no offsetting factor in 2013).

In terms of quantifying the correction, the simplest means of quantifying the correction would be to make use of the model that was used originally to calculate the S factor true up amount to determine the change in the true up amount that would have resulted if year 2010 performance had been known at the time of the price review. The steps to this calculation are as follows:

- First, the calculations need to commence with the model that was used to determine the level of the price controls for 2011 to 2015 regulatory period, populated with the forecasts, which would include the formula for calculating the ‘true up’.

- Secondly, calculate the ‘true up’ using the best forecast of year 2010 performance. The final outworking of this would be a Po and X factors and a forecast of annual revenue (the ‘smoothed revenue requirement’) for the 2011 to 2015 period.

- Thirdly, when year 2010 performance is known, re-run the S factor true up calculation after substituting the known 2010 performance for the forecast. This will result in a different true up amount for 2012 to 2017, and then by a further calculation performed in the JEN S factor model a different true up amount for the 2012 to 2015 period (the model currently brings forward the 2016 and 2017 amounts into 2015 using the pre tax WACC as the discount rate). Note that 2011 is unaffected by year 2010 performance and so can be ignored.

- Thirdly, the required correction (in dollars) is the difference between the new and original true up amounts for 2012 to 2015 (that is, the new true up *less* the original true up).

- Fourthly, the required percentage change to the price level can be calculated by comparing the required correction to the original forecast of revenue (the smoothed revenue requirement). That is, calculate the present value of the required correction for 2012 to 2015 and also calculate the present value of the original forecast of revenue for the 2012 to 2015 period (with both calculated using the pre tax WACC and discounted back to the same point in time, such as the beginning of 2012). The 'factor' that would need to be included on the price control (that is, as a further multiplicative factor) to effect the required price change would then be:

$$SFTUCF = 1 + \frac{PV(Change\ in\ true - up\ \ for\ 2012\ to\ 2015)}{PV(Forecast\ \mathrm{Re}venue\ \ for\ 2012\ to\ 2015)}$$

where SFTUCF stands for the 'S factor true up correction factor'.

This means that the right hand side of the price control for 2012 only would be:

$$\ldots \leq (1 + CPI_t) \times (1 + S_t) \times (1 + L_t) \times (1 + SFTUCF)$$

Note that as this correction factor is based on a comparison of the correction and the revenue forecast over the whole of the 2012 to 2015 period, then there is no need to add a further factor to remove the effect (rather, the intention is that prices be higher or lower by the required amount for the remainder of the period). The correction factor would be removed automatically at the 2016 price review as prices are realigned at that time with cost.

The correction formula discussed above is designed to leave JEN in the position that it would have been in if year 2010 performance was known at the time of the price review. The actual compensation (in dollar terms) will vary with quantities and with the size of other factors (namely the new S factor and the L factor).

17 Efficiency benefit sharing scheme

This chapter sets out JEN's response to the RIN clause 10 requirements on EBSS. It is structured as follows:

- *Summary* - provides an overview of JEN's response and relevant considerations relating to the AER's F&A Paper on the efficiency benefit sharing scheme
- *Changes in capitalisation policy* – identifies the impact of changes made to JEN's capitalisation policy during the current regulatory control period
- *Cost categories* – identifies those cost categories that JEN has excluded from the operation of the EBSS
- *Base year* – sets out JEN's proposed base year to be used in the EBSS
- *Carryover amounts* – sets out JEN's carryover amounts under the EBSS.

17.1 Summary

The EBSS has incentivised JEN to achieve significant opex efficiencies over the current regulatory control period.

These efficiency savings will be shared with JEN's customers over the course of the forthcoming regulatory period through application of the EBSS and the associated use of the revealed 2009 costs to determine JEN's opex forecast.

JEN proposes to apply the EBSS as specified by the AER for the forthcoming regulatory control period.

17.2 Changes in capitalisation policy

Current regulatory control period

Over the current regulatory control period, JEN's capitalisation policy has been consistent with the policy underlying the opex forecasts established by the ESC. The exception to this is the application of the new Jemena group WOBCA in 2008.

Consistent with the AER's EBSS guideline, JEN has adjusted for this change when applying the EBSS.

Commercial in Confidence

Forthcoming regulatory control period

Over the forthcoming regulatory control period, JEN proposes to use the same capitalisation policy as used:

- in the final years of the current regulatory control period
- to determine its expenditure forecast for the forthcoming regulatory control period.

17.3 Growth adjustment

Current regulatory control period

As discussed in section 5.2, JEN has experienced demand growth which has differed from that forecast by the ESC over the current regulatory control period. Consequently JEN has applied a growth adjustment to the EBSS using the growth adjustment method determined by the ESC.

Forthcoming regulatory control period

Consistent with the AER's EBSS guideline, JEN proposes to retain this growth adjustment method and related growth adjustment factors for the EBSS to apply to the forthcoming regulatory control period.

17.4 Cost categories

Current regulatory control period

The AER's F&A Paper provides for DNSPs to exclude costs associated with non-network alternatives from application of the EBSS[68]. This approach avoids discouraging the DNSPs from pursuing these initiatives.

Over the current regulatory period, JEN has made payments to the Somerton power station for avoided network costs. These payments totalled $2.75 million (nominal) over the period 2006 to 2008 and have been excluded from the EBSS.

Forthcoming regulatory control period

JEN has not proposed any forecast expenditure that requires exclusion from the benchmarks for the purpose of applying the EBSS in the forthcoming regulatory control period.

[68] AER, *Final framework and approach paper for Victorian electricity distribution regulation*, May 2009, pp. 111-112.

17.5 Base year

The AER's EBSS guideline[69] and RIN require JEN to nominate a base year for the purpose of applying the EBSS. The guideline provides that this year may be either the penultimate or antepenultimate year of the current regulatory control period.

The EBSS base year determines the point at which the EBSS calculation ceases to rely upon actual opex data and adopts the EBSS final year formula. This formula constrains the resulting deemed opex number to provide a zero carryover value in that year. The fifth year efficiency incentives are then delivered through use of the resulting year five opex value as the starting point for forecasting opex into the forthcoming regulatory control period as discussed in section 9.3.

Consistent with the previous operation of the EBSS under the ESC and with JEN's proposed base year for the purpose of opex forecasting, JEN proposes to adopt 2009 as its base year. This year is the penultimate year of the current regulatory control period. JEN considers this year is the most efficient because it is the most recent full year for which actual data will be available at the time of the AER's determination.

17.6 Carryover amounts

JEN's EBSS carryover amounts are set out in Table 17-1. JEN has calculated all carryover amounts in accordance with the growth adjustment formula and principles on changes to capitalisation policy contained in the ESC's current price determination.

Table 17-1: JEN efficiency carryover amounts

Details, 2010 $m	2011	2012	2013	2014	2015	Total
Carry-over mechanism	19.6	13.6	15.7	0.7	0.0	49.7

[69] AER, *Final Decision Efficiency Benefit Sharing Scheme*, June 2008.

18 Transitional matters

This chapter provides details of the transitional matters arising from the move to a national regulatory framework administered by the AER. These include transitional and savings provisions of the new Rules as well as issues associated with transitioning from the regulatory methods adopted by the ESC to those of the AER.

This chapter is structured as follows:

- *Summary* - provides an overview of the transitional matters arising from the move to a national regulatory framework
- *Taxation treatment* – complies with the Rule requirement to treat tax in accordance with the ESC methods
- *Capex overspend recovery* – details the capital overspend recovery provisions specified by the ESC and the resulting financing cost adjustments JEN is entitled to receive.

18.1 Summary

There are a number of unintended consequences and ambiguities arising from the transition to a national framework, and resulting inconsistencies or gaps in the regulatory framework. JEN has incorporated solutions that are consistent with the NEL objectives, and a pragmatic interpretation of the Rules.

The two key areas where transitional issues arise are:

- retention of the ESC taxation treatment in the tax asset base roll forward
- receipt of financing cost recovery on 2006 to 2010 capex that JEN incurs in excess of the ESC's capex, but within the ESC's capex recovery threshold.

JEN has addressed further transitional matters relating to the price control and STPIS in chapters 14 and 16 respectively.

In addition, JEN has not been able to provide certain information in the form contemplated by the RIN because that information has not been recorded or retained in the relevant form under historic ESC-approved regulatory accounting practices. JEN has used available information to present data in the requested formats to the extent possible. Appendix 6 includes details of all allocators and assumptions used by JEN for this purpose, which JEN considers to be consistent with the substantive requirements of the Rules.

18.2 Tax depreciation

Clause 11.17.2 of the Rules stipulates that the AER is to calculate tax payable based on the method adopted by the ESC. Specifically, Clause 11.17.2(b)(3) states that the AER is to use the same method of tax depreciation as adopted by the ESC. The ESC used the declining balance method and tax depreciation rates as set out in Table 18-1.

Table 18-1: Tax asset depreciation rates

Asset category	Tax asset life
Post business review categories	
Demand related capital expenditure	3.00%
Replacement expenditure (Group 1)	100.00%
Replacement expenditure (Group 2)	7.50%
Replacement expenditure (Group 3)	3.00%
Environment, safety & legal	7.50%
Standard metering (Group 1)	37.50%
Standard metering (Group 2)	10.00%
SCADA/Network control	7.50%
Non-network general assets – IT	40.00%
Non-network general assets – Other	17.65%
Pre-business review categories	
Land	0.00%
6.7 to 10 yrs	30.00%
10 to 13 yrs	25.00%
13 to 30yrs	20.00%
> 30 years	10.00%

Notes: ESC Final Decision model

Clause 11.17.2(c) also states that the AER may only depart from the ESC's tax depreciation method if there is a change in taxation laws or rulings given by the Australian Taxation Office (**ATO**). JEN is not aware of any relevant ATO rulings.

Consequently, JEN has retained the ESC method to roll forward its tax asset base. This has no financial impact on JEN because it does not constitute a change in approach. Similarly, this transitional issue has no affect on JEN's service performance.

18.3 Capex overspend recovery

An important element of the ESC regulatory approach was provision for financing cost recovery on capex in excess of the regulator's allowed forecast. JEN has incurred costs in excess of the ESC's approved forecast and relies upon the certainty intended by the ESC's approach to recover its financing costs on this overspend.

In its final decision on capex forecasts for the current regulatory control period, the ESC significantly reduced the capex forecast relative to that submitted by the Victorian networks including JEN. In JEN's case this reduction amounted to 32 per cent relative to JEN's final proposal.

In making this significant forecast cut, the ESC acknowledged the additional risks this presented to the businesses.[70] Consequently, the ESC foreshadowed that distributors would be able to recover financing costs associated with capital overspends relative to this allowance at the time of the next RAB roll forward. The ESC stated:

> …the Commission recognises that this approach is subject to some risk in that it is conceivable that a distributor's capital expenditure requirements during the 2006-10 period might exceed the forecast capital expenditure. It therefore considers that there should be further flexibility where the distributor requires additional investment. Accordingly, the Commission has decided that, when the capital expenditure incurred by a distributor exceeds the forecast capital expenditure included in its revenue requirement (excluding expenditure associated with reliability improvements or CitiPower's Melbourne CBD security of supply project) the distributor should be able to apply to have the financing costs associated with this higher level of capital expenditure, up to a cap, rolled into the regulatory asset base in 2011. However, the decision on whether to permit such a roll-in of financing costs is ultimately one that is at the discretion of the relevant regulator at that time based on the circumstances that give rise to the additional expenditure.[71]

JEN considers the circumstances giving rise to its capex overspend and the fact that this overspend was within the determined 'expenditure cap', warrant the AER providing financing costs on this amount. Further, JEN considers that its service performance would have deteriorated further had these investments not been made.

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70 ESC, *Electricity Distribution Price Review 2006-10, October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006, Final Decision Volume 1 Statement of Purpose and Reasons*, October 2006, p.270 to 272.

71 Ibid, p. 271.

18.3.1 ESC approach

The ESC's Final Determination stated that:

> "In short, the actual gross capital expenditure in 2006-09 and the forecast gross capital expenditure for 2010 will be rolled into the regulatory asset base at the next price review.
>
> However, to the extent the actual gross capital expenditure in 2006-09 and the forecast gross capital expenditure for 2010 (excluding capital expenditure associated reliability improvements or CitiPower's Melbourne CBD security of supply project) is greater than the forecast expenditure for 2006-10 but equal to a less than the expenditure cap, the financing costs associated with that additional capital expenditure may also be rolled into the regulatory asset base at the next price review.".[72]

The ESC determined the capped capex amount up to which this financing cost recovery would apply by reference to its own consultant's view of capex. For JEN this cap was $289.5 million ($2004) or $343.4 million ($31/12/10).[73] JEN's actual 2006-2010 spend of $372.6 million ($2010) is above this cap and the ESC approved allowance of $232.8 million ($2004) of $276.8 million ($2010). JEN considers that the cap should be adjusted to reflect JEN's out-turn customer growth which led to significantly higher customer initiated capex than was contemplated in the Wilson Cook review commissioned by the ESC.

18.3.2 Financing cost adjustment

Applying the ESC method to JEN's qualifying capital overspend results in a required financing cost adjustment to JEN's allowed revenues of $12.4 million. This calculation is set out in Appendix 13.

72 Ibid, p.272.

73 Ibid, p.272.

19 Alternative control services

This chapter sets out JEN's regulatory proposal for its alternative control services (**ACS**), in compliance with RIN 15 and Rules 6.8.2(c)(3). JEN's proposed ACS are listed below:

1. manual energisation of new premises
2. temporary supply (overhead supply - coincident abolishment)
3. temporary disconnect / reconnect for non-payment
4. manual de-energisation - existing premises
5. manual re-energisation - existing premises
6. manual special meter read
7. remote special meter read
8. remote re-energisation
9. remote de-energisation
10. remote meter reconfiguration
11. adjust time switch
12. service vehicle visit
13. wasted service truck visit – not DNSP fault
14. temporary cover of low voltage wires
15. meter test
16. metering data provider services for unmetered supplies with type 7 metering installations
17. recoverable works:
    a. damage to overhead service cables caused by high loads
    b. high load escorts – lifting of overhead lines
    c. supply abolishment

d. rearrangement of network assets at customer request, excluding alteration and relocation of existing public lighting services

e. supply enhancement at customer request-elective underground service where an existing overhead service exists

f. location of underground cables

18. supply enhancement at customer request-reserve feeder

19. public lighting

This chapter is structured as follows:

- *Summary* - provides an overview of the key messages
- *Background*—provides the contextual background for JEN's ACS
- *Method for Deriving Proposed Charges* – sets out the high-level approach JEN adopted in developing its proposed charges for ACS
- *Rationalisation of Legacy Services and Introduction of New Services* – explains how JEN has rationalised the structure of ACS in its regulatory proposal, compared to the historic treatment of these services
- *Method for existing charges for excluded services* – explains how charges for current excluded services were set
- *Service-specific Sub-chapters* – set out information in relation to each alternative control service. All prices are exclusive of GST, unless explicitly stated otherwise.

19.1 Summary

In summary:

- ACS are mainly former excluded services
- with the exception of public lighting, charges for ACS services have not been updated for two regulatory periods and therefore are not aligned with the costs of providing the service
- JEN has undertaken a comprehensive bottom-up costing exercise to determine the costs of providing ACS, except for metering data provider services for unmetered supplies with type 7 metering installations and supply enhancement at customer request-reserve feeder, which are based on a top-down approach

- except for the two services where the top-down approach is adopted, JEN's proposed ACS charges reflect the bottom-up costs as per its agreed AMA with its service provider. The charges reflect JEN's best estimate of the actual costs JEN incurs in providing the service to the customer. No profit margin for JEN has been included

- JEN has taken the opportunity to simplify and rationalise the legacy structure of the charges. JEN has also introduced new services that will become available in the upcoming regulatory period due to the roll out of Advanced Interval Meters.

19.2 Background

Most of JEN's ACS have been treated as excluded services in the current and previous regulatory periods by the ESC. Given the small proportion of revenue that these services account for, they were not a major focus of the 2006 and 2001 price reviews. In fact most of the charges were set prior to 2001 and have not changed since. Information on the basis for the original pricing is scarce, although at least for some services prices were set to reflect estimates of the costs of providing the service at the time (late 1990s).

Over the last two regulatory periods the costs of providing ACS have increased significantly, as can be seen in the analysis provided in the sub-chapters that relate to individual services. This is unsurprising, given that in many cases more than a decade has passed since the current price was set.

19.3 Method for deriving proposed charges

In the F&A Paper the AER noted that the control mechanism to apply to ACS will be:

- a CPI-X price cap for public lighting services classified as ACS based on a limited building block approach

- a CPI-X price cap for all other ACS based on either a 'bottom up' or a 'top down' approach, with the AER to specify in the RIN which services must be established using which approach

In the following sections, JEN explains the overarching method used to develop proposed charges for routine ACS, being all ACS, with the exception of:

- public lighting

- supply enhancement at customer request-reserve feeder

- metering data provider services for unmetered supplies with type 7 metering installations.

Customised methodologies apply to those three services (non-routine ACS). These methodologies are described in the relevant sub-chapters for each of these services.

19.3.1 Overarching cost build up method for routine ACS

In relation to all ACS other than public lighting, the AER's RIN did not provide guidance on when a bottom-up or a top-down approach should be used. In the absence of guidance from the AER, JEN has adopted a bottom up approach for all such services, with the exception of metering data provider services for unmetered supplies with type 7 metering installations and reserve feeder services, for which the top-down approach was used. The method used to develop bottom-up costs and charges for routine ACS is described below.

In deriving the proposed indicative charges for routine ACS, JEN has followed an overarching method of passing on JEN's best estimates of its actual costs of providing the service to the customer. JEN's actual costs incurred in providing the service are the charges it pays to JAM for providing the service, which comprise:

- JAM's direct costs of providing the service
- an allocation of JAM's indirect costs of providing the service
- JAM's margin charged under the AMA.

JAM direct costs

Direct costs are built up using a managerial assessment of:

- the number of people involved in delivering the service
- average time taken to deliver the service
- the labour rates applicable for the JAM staff undertaking the work (for in house resources) or the labour rates for the relevant external sub-contractor (as some of these services are now being outsourced to external parties)
- type and average quantity of materials consumed for each service using stores material cost rates
- motor vehicle and plant charge out rates.

Detailed calculations and assumptions on direct costs (as well as all other costs) for each routine ACS are provided in Appendix 16[74].

Commercial in Confidence

Shared assets

No shared assets have been allocated to the costs of providing ACS and thus the costs of ACS are entirely opex costs.

The only assets used in the provision of routine ACS are motor vehicles and plant. JEN's systems do not specifically assign those assets that are used for the provision of standard control, alternative control, negotiated or unregulated services, as JEN does not split its assets in the general ledger system across the different types of services performed. The assets are therefore allocated to those services for which these assets are used most, being standard control services. The costs of operating these assets to provide routine ACS is reflected in the cost build-up for the relevant service via a fleet charge out rate.

Avoidance of double recovery

In calculating JEN's proposed base year standard control costs which are inputted into the AER's PTRM, JEN has explicitly removed the costs that related to alternative control services. The explicit adjustment can be found in the Forecast Opex sheet (row 35) of the Forecast Data Model.

[74] The figures in Appendix 16 are in \$2008, those figures are then escalated to arrive at \$2010 indicative charges provided in the following sections. The escalation calculation can be found in the ACS Prices sheet of the Forecast Data Model attached as Appendix 13.

Appendix 16 provides a detailed cost build up for each routine ACS, including the overhead allocation applied, the unit rates (where relevant) and the estimated direct costs of providing the service.

JEN is not proposing to change the terms and conditions on which ACS are provided in the current regulatory period.

19.3.2 Price control parameters

JEN's proposed indicative routine ACS charges reflect an approach whereby:

- as at 1 January 2011, charges will be set to reflect the estimate of actual costs of providing the relevant service
- each year, charges are adjusted by (1+CPI)(1-X) similarly to standard control service charges, where X reflects the escalation of cost inputs to the service in real terms.

For the purposes of proposing indicative prices, JEN has calculated X factors by breaking down the costs of the service into individual labour and material components and applying the escalators forecast by the independent experts—BIS Shrapnel (for labour) and SKM (for materials).

19.4 Rationalisation of legacy services and introduction of new services

Through the 'bottom up' costing process, JEN has established that a number of the legacy excluded services that have been classified as ACS share similar characteristics and have similar underlying costs. Where this was found to be the case, JEN has proposed to merge the relevant services into one. This provides a simpler and clearer set of services. Table 19-1 provides a reconciliation of the names of the current excluded services to their equivalent proposed ACS names. Some services have also been renamed to improve the accuracy of the description. Finally, some new services have been introduced in anticipation of the new functionality that will become available following the introduction of advanced interval metering.

Table 19-1: Comparison of services

Excluded Service	Equivalent Alternative Control Service
N/A – not previously a separate service	Manual energisation of new premises
Temporary overhead supply – Coincident abolishment	Temporary supply (overhead supply - coincident abolishment)
Re-energisation after de-energisation for non-payment	Temporary disconnect / reconnect for non-payment

Excluded Service	Equivalent Alternative Control Service
Fuse Removal	Manual de-energisation - existing premises
Fuse Insertion	Manual re-energisation - existing premises
Special Reads	Manual special meter read
N/A – new service	Remote special meter read
N/A – new service	Remote re-energisation
N/A – new service	Remote de-energisation
N/A – new service	Remote meter reconfiguration
Adjust time switch	Adjust time switch
Service Vehicle Visit	Service vehicle visit
	Wasted service vehicle visit – Not DNSP fault
Cover Service Cable	Temporary cover of low voltage wires
Second and subsequent months rental of covers – service wire (see note 1)	
Cover Low Voltage mains – 2 wire	
Second and subsequent months rental of covers – 2 wire (see note 1)	
Cover low voltage mains – all wires	
Second and subsequent months rental of covers – all wires (Note: there is only one upfront charge (no future monthly rentals)	
Re-test of types 5 & 6 meter installations for first tier customers with annual consumption >160 MWh	Meter test
Single phase meter test – first meter	
Single phase meter test – second and subsequent meters	
Multi phase meter test – first meter	
Multi phase meter test – second and subsequent meters	
Meter Data Provider Services for unmetered supplies with Type 7 meter installations	Metering data provider services for unmetered supplies with type 7 metering installations
	Recoverable works – damage to overhead

Excluded Service	Equivalent Alternative Control Service
Recoverable works	service cables caused by high loads
	Recoverable works – high load escorts, lifting of overhead lines
	Recoverable works – supply abolishment
	Recoverable works – rearrangement of network assets at customer request, excluding alteration and relocation of existing public lighting services
	Recoverable works – supply enhancement at customer request-elective underground service where an existing overhead service exists
	Recoverable works – location of underground cables
Feeder Reserve charge	Supply enhancement at customer request – reserve feeder

19.5 Method for existing charges for excluded services

The current charges for excluded services (which all routine ACS are currently treated as) were established and approved in the late 1990's. To JEN's best knowledge, at the time the charges were set, the basis for the pricing of the services was to:

- estimate the costs of delivering the relevant service
- allow for a 20 per cent profit margin to the total estimated cost.

In July 2000, with the introduction of GST, 10 per cent GST was also added. Finally, prices for services delivered after hours were set to reflect the higher costs of labour after business hours. The current set of charges was approved by the ESC in the 2006 EDPR based on prices in the 2001-2005 regulatory period.

19.6 Manual energisation of new premises

19.6.1 Service description

This service is provided to customers moving into a new premise, where the new connection has been established but not energised and thus only energisation (fuse insertion) is required. The build up of the charge includes labour and transport and covers energisation of either overhead or underground supplies.

19.6.2 Current charges

This service is not currently separated from other types of fuse insertion services. The current charges for fuse insertion are $20.91 during business hours and $121.64 after hours. JEN does not expect these prices to change in 2010, as JEN's proposed changes to the price for this service would only come into effect in the forthcoming regulatory control period. The method for deriving the existing prices for fuel insertion is set out in section 19.10.

19.6.3 Proposed control mechanism and charges

JEN proposes that, consistent with the current treatment of this service, the charges be controlled by way of price cap on the actual charge to the customer.

Table 19-2, below provides indicative prices and X factors in accordance with the proposed control mechanism.

Table 19-2: Indicative prices for the forthcoming regulatory control period

Year	2011	2012	2013	2014	2015
Price – bus hrs ($ real 2010)	42.45	43.60	44.80	45.95	47.10
Price – after hrs ($ real 2010)	70.75	72.60	74.70	76.60	78.40
X (per cent)	-2.30%	-2.63%	-2.80%	-2.60%	-2.40%

The detailed assumptions and unit cost inputs used to build up the underlying costs for the proposed charges are provided in Appendix 16.

19.6.4 Service quantities and revenues

As historically this service has not been treated separately from fuse insertion for existing premises, JEN has not provided separate revenue and service quantity figures for the current regulatory period. The quantities and revenues for the existing fuse insertion service are provided in section 19.10.

19.7 Temporary supply (overhead supply - coincident abolishment)

19.7.1 Service description

A temporary supply connection is provided where supply is requested for a known limited period, generally a few weeks, but may extend up to five years. Temporary supplies may be provided for such purposes as:

- construction of buildings and roads
- mobile services, such as health service and X-Ray vans

- events, such as carnivals, fetes and festivals.

Where this service relates to a situation where the temporary supply connection will be abolished in conjunction with the installation of a permanent connection service, the cost of the coincident abolishment is included. If an independent abolishment of a temporary supply is requested (i.e. no permanent connection takes place at the time of abolishment), a service truck visit charge will also apply.

19.7.2 Current charges

The current charges for this service are $185.55 during business hours and $360.00 after hours. JEN does not expect these prices to change in 2010, as JEN's proposed changes to the price for this service would only come into effect in the forthcoming regulatory period. As noted in section 19.5, which sets out the method for current charges, these charges were set in the 1990's and JEN has been unable to obtain the unit cost inputs used at the time.

19.7.3 Proposed control mechanism and charges

JEN proposes that, consistent with the current treatment of this service, the charges be controlled by way of price cap on the actual charge to the customer.

Table 19-3, below provides indicative prices and X factors in accordance with the proposed control mechanism.

Table 19-3: Indicative prices for the forthcoming regulatory control period

Year	2011	2012	2013	2014	2015
Price – bus hrs ($ real 2010)	453.35	463.00	473.20	483.30	492.80
Price – after hrs ($ real 2010)	1017.80	1042.25	1068.25	1093.95	1118.30
X (per cent)	-2.00%	-2.13%	-2.20%	-2.13%	-1.97%

The detailed assumptions and unit cost inputs used to build up the underlying costs for the proposed charges are provided in Appendix 16.

19.7.4 Service quantities and revenues

Table 19-4 below sets out the quantities and revenues for this service in the current regulatory period, with 2009 and 2010 figures being estimates.

Table 19-4: Quantities and revenues in the current regulatory control period

Year	2006	2007	2008	2009	2010
Revenue ($ real 2010)	171,262	167,218	166,080	158,199	156,229
Service Quantity (times service provided)	820	832	842	842	842

Note: Service Quantities are actual for 2008, with estimates for all future and past years. Historic quantities need to be estimated as, due to a change of ownership, JEN does not have access to detailed primary information on the number of services provided in 2006 and 2007 for this service. Revenues are estimated by multiplying current prices by estimated service quantities, as JEN's systems do not separately track revenues for this service.

19.8 Temporary disconnect / reconnect for non-payment

19.8.1 Service description

This service is provided where a supply point is re-energised after a customer premise has been de-energised for non-payment. The charge build up for this service assumes that all supply assets remain at the customer's installation from the time when the supply point is de-energised. Re-energisation requests received prior to 3pm incur a business hours fee and after hours fees apply to requests received between 3pm until 9pm. Other charges may apply if additional work is required or if there are site problems, such as wasted truck visit.

19.8.2 Current charges

The current charges for this service are $48.82 during business hours and $149.64 after hours. JEN does not expect these prices to change in 2010, as JEN's proposed changes to the price for this service would only come into effect in the forthcoming regulatory period.

As noted in section 19.5, which sets out the method for current charges, these charges were set in the 1990's and JEN has been unable to obtain the unit cost inputs used at the time.

19.8.3 Proposed control mechanism and charges

JEN proposes that, consistent with the current treatment of this service, the charges be controlled by way of price cap on the actual charge to the customer.

Table 19-5, below provides indicative prices and X factors in accordance with the proposed control mechanism.

Table 19-5: Indicative prices for the forthcoming regulatory control period

Year	2011	2012	2013	2014	2015
Price – bus hrs ($ real 2010)	57.95	59.50	61.20	62.75	64.25
Price – after hrs ($ real 2010)	70.75	72.60	74.70	76.60	78.40
X (per cent)	-2.20%	-2.63%	-2.86%	-2.58%	-2.38%

The detailed assumptions and unit cost inputs used to build up the underlying costs for the proposed charges are provided in Appendix 16.

19.8.4 Service quantities and revenues

Table 19-6 below sets out the quantities and revenues for this service in the current regulatory period, with 2009 and 2010 figures being estimates.

Table 19-6: Quantities and revenues in the current regulatory control period

Year	2006	2007	2008	2009	2010
Revenue ($ real 2010)	102,814	100,585	99,900	95,160	93,975
Service Quantity (times service provided)	1,690	1,715	1,735	1,735	1,735

Note: Service Quantities are actual for 2008, with estimates for all future and past years. Historic quantities need to be estimated as, due to a change of ownership, JEN does not have access to detailed primary information on the number of services provided in 2006 and 2007 for this service. Revenues are estimated by multiplying current prices by estimated service quantities, as JEN's systems do not separately track revenues for this service.

19.9 Manual de-energisation - existing premises

19.9.1 Service description

The manual de-energisation service is provided where a customer or a retailer on behalf of a customer has requested power to a premise to be turned off and the fuse is removed.

19.9.2 Current charges

The current charges for fuse removal are $20.91 during business hours and $121.64 after hours. JEN does not expect these prices to change in 2010, as JEN's proposed changes to the price for this service would only come into effect in the forthcoming regulatory period.

As noted in section 19.5, which sets out the method for current charges, these charges were set in the 1990's and JEN has been unable to obtain the unit cost inputs used at the time.

19.9.3 Proposed control mechanism and charges

JEN proposes that, consistent with the current treatment of this service, the charges be controlled by way of price cap on the actual charge to the customer.

Table 19-7, below provides indicative prices and X factors in accordance with the proposed control mechanism.

Table 19-7: Indicative prices for the forthcoming regulatory control period

Year	2011	2012	2013	2014	2015
Price – bus hrs ($ real 2010)	47.40	48.60	50.00	51.30	52.50
Price – after hrs ($ real 2010)	70.75	72.60	74.70	76.60	78.40
X (per cent)	-2.26%	-2.63%	-2.82%	-2.59%	-2.39%

The detailed assumptions and unit cost inputs used to build up the underlying costs for the proposed charges are provided in Appendix 16.

19.9.4 Service quantities and revenues

Table 19-8 below sets out the quantities and revenues for this service in the current regulatory period, with 2009 and 2010 figures being estimates.

Table 19-8: Quantities and revenues in the current regulatory control period

Year	2006	2007	2008	2009	2010
Revenue ($ real 2010)	520,628	508,334	504,874	480,919	474,929
Service Quantity (times service provided)	1,690	1,715	1,735	1,735	1,735

Note: Service Quantities are actual for 2008, with estimates for all future and past years. Historic quantities need to be estimated as, due to a change of ownership, JEN does not have access to detailed primary information on the number of services provided in 2006 and 2007 for this service. Revenues are estimated by multiplying current prices by estimated service quantities, as JEN's systems do not separately track revenues for this service.

19.10 Manual re-energisation - existing premises

19.10.1 Service description

The manual re-energisation service is provided to customers moving into an existing premise where a connection exists, but the power is off and a re-energisation (fuse insertion) is required. The charge build up for this service includes labour and transport and covers re-energisation of either overhead or underground supplies. Where a premise has been off supply in excess of 12 months, a non-prescribed Certificate of Electrical Safety is required from a Registered Electrical Contractor (**REC**) before energisation can be carried out.

19.10.2 Current charges

The current charges for fuse insertion are $20.91 during business hours and $121.64 after hours. JEN does not expect these prices to change in 2010, as JEN's proposed changes to the price for this service would only come into effect in the forthcoming regulatory period.

As noted in section 19.5, which sets out the method for current charges, these charges were set in the 1990's and JEN has been unable to obtain the unit cost inputs used at the time.

19.10.3 Proposed control mechanism and charges

JEN proposes that, consistent with the current treatment of this service, the charges be controlled by way of price cap on the actual charge to the customer.

Table 19-9, below provides indicative prices and X factors in accordance with the proposed control mechanism.

Table 19-9: Indicative prices for the forthcoming regulatory control period

Year	2011	2012	2013	2014	2015
Price – bus hrs ($ real 2010)	42.45	43.60	44.80	45.95	47.10
Price – after hrs ($ real 2010)	70.75	72.60	74.70	76.60	78.40
X (per cent)	-2.30%	-2.63%	-2.80%	-2.60%	-2.40%

The detailed assumptions and unit cost inputs used to build up the underlying costs for the proposed charges are provided in Appendix 16.

19.10.4 Service quantities and revenues

Table 19-10 below sets out the quantities and revenues for this service in the current regulatory period, with 2009 and 2010 figures being estimates.

Table 19-10: Quantities and revenues in the current regulatory control period

Year	2006	2007	2008	2009	2010
Revenue ($ real 2010)	1,194,198	1,165,996	1,158,061	1,103,114	1,089,374
Service Quantity (times service provided)	46,724	47,418	47,972	47,972	47,972

Note: Service Quantities are actual for 2008, with estimates for all future and past years. Historic quantities need to be estimated as, due to a change of ownership, JEN does not have access to detailed primary information on the number of services provided in 2006 and

2007 for this service. Revenues are estimated by multiplying current prices by estimated service quantities, as JEN's systems do not separately track revenues for this service.

19.11 Manual special meter read

19.11.1 Service description

A manual special meter read service is provided when a meter needs to be read outside the cycle of a scheduled read. A special read may be required for the purposes of rendering billing associated with the customer moving in or out of the premise, or to verify the meter reading due to an account complaint. In the latter case, the charge only applies if the original reading is found to be correct. Special reads are also required to enable transfer of customers between retailers outside the normal meter reading schedule.

19.11.2 Current charges

The current charges for a special meter read are $20.91 during business hours and $121.64 after hours, although JEN has not provided this service after hours in 2008 as it was not requested. JEN does not expect these prices to change in 2010, as JEN's proposed changes to the price for this service would only come into effect in the forthcoming regulatory period.

As noted in section 19.5, which sets out the method for current charges, these charges were set in the 1990's and JEN has been unable to obtain the unit cost inputs used at the time.

19.11.3 Proposed control mechanism and charges

JEN proposes that, consistent with the current treatment of this service, the charges be controlled by way of price cap on the actual charge to the customer.

Table 19-11, below provides indicative prices and X factors in accordance with the proposed control mechanism. JEN has not proposed an afterhours manual special meter read service, given that not a single such service was provided in 2008. JEN is of the view that retailers are unlikely to request such a service in the future.

Table 19-11: Indicative prices for the forthcoming regulatory control period

Year	2011	2012	2013	2014	2015
Price ($ real 2010)	39.00	40.00	41.15	42.20	43.20
X (per cent)	-2.33%	-2.63%	-2.78%	-2.61%	-2.41%

The detailed assumptions and unit cost inputs used to build up the underlying costs for the proposed charges are provided in Appendix 16.

19.11.4 Service quantities and revenues

Table 19-12 below sets out the quantities and revenues for this service in the current regulatory period, with 2009 and 2010 figures being estimates.

Table 19-12: Quantities and revenues in the current regulatory control period

Year	2006	2007	2008	2009	2010
Revenue ($ real 2010)	304,781	297,584	295,558	281,535	278,028
Service Quantity (times service provided)	12,951	13,143	13,297	13,297	13,297

Note: Service Quantities are actual for 2008, with estimates for all future and past years. Historic quantities need to be estimated as, due to a change of ownership, JEN does not have access to detailed primary information on the number of services provided in 2006 and 2007 for this service. Revenues are estimated by multiplying current prices by estimated service quantities, as JEN's systems do not separately track revenues for this service.

19.12 Remote special meter read

19.12.1 Service description

Remote special meter reading will become possible due to the Advanced Interval Metering Roll-out (**AIMRO**) mandated by the Victorian government. This functionality will become gradually available to an increasing number of sites over the forthcoming regulatory period and is subject to the successful implementation of the AIMRO program. The functionality provided is identical to a manual special meter read. However, the underlying costs of the service are different, as the service will be provided remotely rather than through a site visit from a meter reader. The remote special meter read charge will be applied where the service is provided remotely, with the manual special meter read charge applying where the special meter read is provided manually.

19.12.2 Current charges

The service is not currently provided and thus there is no established current charge for the service. The charges for a manual special meter read are set out in the previous sub-chapter. As for the manual special meter read, JEN will not be providing the remote special meter read service after hours.

19.12.3 Proposed control mechanism and charges

JEN proposes that, consistent with the current treatment of the manual provision of this service, the charges be controlled by way of price cap on the actual charge to the customer.

Table 19-13, below provides indicative prices and X factors in accordance with the proposed control mechanism. The indicative prices for this service are substantively lower than the prices for the equivalent manually-provided service.

Table 19-13: Indicative prices for the forthcoming regulatory control period

Year	2011	2012	2013	2014	2015
Price – bus hrs ($ real 2010)	15.55	16.00	16.40	16.85	17.25
X (per cent)	-2.43%	-2.63%	-2.73%	-2.63%	-2.43%

The detailed assumptions and unit cost inputs used to build up the underlying costs for the proposed charges are provided in Appendix 16.

As this service is not currently provided, no quantities and revenues for this service exist in the current regulatory period.

19.13 Remote re-energisation

19.13.1 Service description

Remote re-energisation will become possible due to AIMRO. If safety approval for new operating modes is provided by Electricity Safety Victoria, this functionality will become gradually available to an increasing number of sites over the forthcoming regulatory period, subject to the successful implementation of the AIMRO program. The functionality provided is identical to a manual re-energisation. However, the underlying costs of the service are different, as the service will be provided remotely rather than through a site visit from a meter reader. The remote re-energisation charge will be applied where the service is provided remotely, with the manual re-energisation charge applying where the re-energisation is provided manually.

19.13.2 Current charges

The service is not currently provided and thus there is no established current charge for the service. The charges for a manual re-energisation are set out in sub-chapter 19.10.

19.13.3 Proposed control mechanism and charges

JEN proposes that, consistent with the current treatment of the manual provision of this service, the charges be controlled by way of price cap on the actual charge to the customer.

Table 19-14, below provides indicative prices and X factors in accordance with the proposed control mechanism. The indicative prices for this service are substantively lower than the prices for the equivalent manually-provided service.

Table 19-14: Indicative prices for the forthcoming regulatory control period

Year	2011	2012	2013	2014	2015
Price – bus hrs ($ real 2010)	13.00	13.35	13.70	14.10	14.40
Price – after hrs ($ real 2010)	13.00	13.35	13.70	14.10	14.40
X (per cent)	-2.43%	-2.63%	-2.73%	-2.63%	-2.43%

The detailed assumptions and unit cost inputs used to build up the underlying costs for the proposed charges are provided in Appendix 16.

As this service is not currently provided, no quantities and revenues for this service exist in the current regulatory period.

19.14 Remote de-energisation

19.14.1 Service description

Remote de-energisation will become possible due to AIMRO. This functionality will become gradually available to an increasing number of sites over the forthcoming regulatory period, subject to the successful implementation of the AIMRO program. The functionality provided is identical to a manual de-energisation. However, the underlying costs of the service are different, as the service will be provided remotely rather than through a site visit from a meter reader. The remote de-energisation charge will be applied where the service is provided remotely, with the manual de-energisation charge applying where the de-energisation is provided manually.

19.14.2 Current charges

The service is not currently provided and thus there is no established current charge for the service. The charges for a manual de-energisation are set out in sub-chapter 19.9.

19.14.3 Proposed control mechanism and charges

JEN proposes that, consistent with the current treatment of the manual provision of this service, the charges be controlled by way of price cap on the actual charge to the customer.

Table 19-15, below provides indicative prices and X factors in accordance with the proposed control mechanism. The indicative prices for this service are substantively lower than the prices for the equivalent manually-provided service.

Table 19-15: Indicative prices for the forthcoming regulatory control period

Year	2011	2012	2013	2014	2015
Price – bus hrs ($ real 2010)	13.00	13.35	13.70	14.10	14.40
Price – after hrs ($ real 2010)	13.00	13.35	13.70	14.10	14.40
X (per cent)	-2.43%	-2.63%	-2.73%	-2.63%	-2.43%

The detailed assumptions and unit cost inputs used to build up the underlying costs for the proposed charges are provided in Appendix 16.

As this service is not currently provided, no quantities and revenues for this service exist in the current regulatory period.

19.15 Remote meter reconfiguration

19.15.1 Service description

The remote meter reconfiguration service will become possible due to AIMRO. This functionality will become gradually available to an increasing number of sites over the forthcoming regulatory period, subject to the successful implementation of the AIMRO program. The service will be provided to a customer through a retailer acting on behalf of a customer, who has requested the re-configuration of an advanced interval meter. Examples of meter configuration include, but are not limited to:

- reconfiguration of the time of use periods or maximum demand settings in a meter, to align the meter with a tariff change
- reconfiguration following the installation of a solar installation in order to measure import and export of energy flows
- reconfiguration of load control turn-on/turn-off times.

19.15.2 Current charges

The service is not currently provided and thus there is no established current charge for the service. JEN will not be providing this service after hours.

19.15.3 Proposed control mechanism and charges

JEN proposes that the charges for this service be controlled by way of price cap on the actual charge to the customer.

Table 19-16, below provides indicative prices and X factors in accordance with the proposed control mechanism.

Table 19-16: Indicative prices for the forthcoming regulatory control period

Year	2011	2012	2013	2014	2015
Price – bus hrs ($ real 2010)	65.65	67.35	69.20	71.00	72.75
X (per cent)	-2.43%	-2.63%	-2.73%	-2.63%	-2.43%

The detailed assumptions and unit cost inputs used to build up the underlying costs for the proposed charges are provided in Appendix 16.

As this service is not currently provided, no quantities and revenues for this service exist in the current regulatory period.

19.16 Adjust time switch

19.16.1 Service description

The adjust time switch service is to a customer through a retailer acting on behalf of a customer who requests adjustment of the time switch of different meter registers (for example, off peak) for the customer's benefit. The charge applies to each visit to the site for the purpose of adjusting the time switch.

19.16.2 Current charges

The current charge for this service is $27.91 during business hours. JEN does not provide this service after hours. JEN does not expect this price to change in 2010, as JEN's proposed changes to the price for this service would only come into effect in the forthcoming regulatory period.

As noted in section 19.5, which sets out the method for current charges, this charge was set in the 1990's and JEN has been unable to obtain the unit cost inputs used at the time.

19.16.3 Proposed control mechanism and charges

JEN proposes that, consistent with the current treatment of this service, the charges be controlled by way of price cap on the actual charge to the customer.

Table 19-17, below provides indicative prices and X factors in accordance with the proposed control mechanism.

Table 19-17: Indicative prices for the forthcoming regulatory control period

Year	2011	2012	2013	2014	2015
Price – bus hrs ($ real 2010)	37.05	38.00	39.05	40.10	41.05
X (per cent)	-2.36%	-2.63%	-2.77%	-2.61%	-2.41%

The detailed assumptions and unit cost inputs used to build up the underlying costs for the proposed charges are provided in Appendix 16.

19.16.4 Service quantities and revenues

Table 19-18 below sets out the quantities and revenues for this service in the current regulatory period, with 2009 and 2010 figures being estimates.

Table 19-18: Quantities and revenues in the current regulatory control period

Year	2006	2007	2008	2009	2010
Revenue ($ real 2010)	1,040	1,016	1,009	961	949
Service Quantity (times service provided)	33	34	34	34	34

Note: Service Quantities are actual for 2008, with estimates for all future and past years. Historic quantities need to be estimated as, due to a change of ownership, JEN does not have access to detailed primary information on the number of services provided in 2006 and 2007 for this service. Revenues are estimated by multiplying current prices by estimated service quantities, as JEN's systems do not separately track revenues for this service.

19.17 Service vehicle visit

19.17.1 Service description

The service vehicle visit service is provided and a charge applies whenever a customer, retailer or contractor requests attendance of a service vehicle (except in emergency situations and fault calls). Examples of a situation where a service truck visit is required are as follows:

- de-energisation (fuse removal) where supply is greater than 100 amps
- supply alterations, additions' and upgrades, and
- other related distribution network work undertaken by JEN due to a customer's request.

19.17.2 Current charges

The current charges for this service are $178.55 during business hours and $224.45 after hours. JEN does not expect these prices to change in 2010, as JEN's proposed changes to the price for this service would only come into effect in the forthcoming regulatory period.

As noted in section 19.5, which sets out the method for current charges, these charges were set in the 1990's and JEN has been unable to obtain the unit cost inputs used at the time.

19.17.3 Proposed control mechanism and charges

JEN proposes that, consistent with the current treatment of this service, the charges be controlled by way of price cap on the actual charge to the customer.

Table 19-19, below provides indicative prices and X factors in accordance with the proposed control mechanism.

Table 19-19: Indicative prices for the forthcoming regulatory control period

Year	2011	2012	2013	2014	2015
Price – bus hrs ($ real 2010)	300.70	307.70	315.15	322.55	329.55
Price – after hrs ($ real 2010)	676.95	693.85	711.85	729.65	746.55
X (per cent)	-2.15%	-2.33%	-2.43%	-2.34%	-2.17%

The detailed assumptions and unit cost inputs used to build up the underlying costs for the proposed charges are provided in Appendix 16.

19.17.4 Service quantities and revenues

Table 19-20 below sets out the quantities and revenues for this service in the current regulatory period, with 2009 and 2010 figures being estimates.

Table 19-20: Quantities and revenues in the current regulatory control period

Year	2006	2007	2008	2009	2010
Revenue ($ real 2010)	951,416	928,948	922,626	878,850	867,903
Service Quantity (times service provided)	4,622	4,690	4,745	4,745	4,745

Note: Service Quantities are actual for 2008, with estimates for all future and past years. Historic quantities need to be estimated as, due to a change of ownership, JEN does not have access to detailed primary information on the number of services provided in 2006 and 2007 for this service. Revenues are estimated by multiplying current prices by estimated service quantities, as JEN's systems do not separately track revenues for this service.

19.18 Wasted service truck visit – not DNSP fault

19.18.1 Service description

JEN proposes that a wasted service vehicle visit charge apply to all customer and contractor requested service vehicle visits attended by JEN where, on arrival by the vehicle, it is found that the customer or contractor is not ready for the scheduled work, or JEN's attendance was not required (for example, a customer reports a fault, without checking that the main switch or safety switch is on and the position of the switch turns out to be the cause of non-supply). JEN also proposes that a wasted truck visit charge also apply if less than 24 hours notice is given to cancel a pre-arranged visit.

19.18.2 Current charges

This service is not currently distinguished from the service vehicle visit service. Accordingly, current charges for this service (including the methodologies and unit rates) are the same as those for the service vehicle visit service discussed in the previous sub-chapter. JEN does not expect these prices to change in 2010, as JEN's proposed changes to the price for this service would only come into effect in the forthcoming regulatory period.

19.18.3 Proposed control mechanism and charges

JEN proposed control mechanism and indicative prices for this service are the same as those for the service vehicle visit service discussed in the previous sub-chapter.

19.18.4 Service quantities and revenues

JEN does not track the revenues and quantities for this service separately from the service vehicle visit service. The relevant quantities and revenues for that service in the current regulatory period are provided in the previous sub-chapter.

19.19 Temporary cover of low voltage wires

19.19.1 Service description

This service is provided to customers or contractors who request covering of service cable or low voltage power lines for safety reasons. For example, if those lines are close to a construction site.

19.19.2 Current charges

Currently this service is broken down into multiple components, which are set out in Table 19-21 below.

Table 19-21: Current Charges for Temporary Cover of LV Wires

Service Components	Bus hrs	After hours
Cover Service Cable	332.18	n/a
Second and subsequent months rental of covers – service wire	59.82	n/a
Cover Low Voltage mains – 2 wire	661.45	798.18
Second and subsequent months rental of covers – 2 wire	47.82	n/a
Cover low voltage mains – all wires	673.45	810.00

Service Components	Bus hrs	After hours
Second and subsequent months rental of covers – all wires	59.82	n/a

JEN does not expect the above prices to change in 2010, as JEN's proposed changes to the price for this service would only come into effect in the forthcoming regulatory period.

As noted in section 19.5, which sets out the method for current charges, these charges were set in the 1990's and JEN has been unable to obtain the unit cost inputs used at the time.

19.19.3 Proposed control mechanism and charges

JEN proposes that, consistent with the current treatment of this service, the charges be controlled by way of price cap on the actual charge to the customer. However, JEN has simplified the structure of the charges and proposes to establish a single charge per bay of conductors covered.

Table 19-22 below provides indicative prices and X factors in accordance with the proposed control mechanism.

Table 19-22: Indicative prices for the forthcoming regulatory control period

Year	2011	2012	2013	2014	2015
Price – bus hrs ($ real 2010)	300.70	307.70	315.15	322.55	329.55
Price – after hrs ($ real 2010)	676.95	693.85	711.85	729.65	746.55
X (per cent)	-2.15%	-2.33%	-2.43%	-2.34%	-2.17%

The detailed assumptions and unit cost inputs used to build up the underlying costs for the proposed charges are provided in Appendix 16.

19.19.4 Service quantities and revenues

Table 19-23 below sets out the quantities and revenues for this service in the current regulatory period, with 2009 and 2010 figures being estimates.

Table 19-23: Quantities and revenues in the current regulatory control period

Year	2006	2007	2008	2009	2010
Revenue ($ real 2010)	139,182	135,340	134,417	128,039	126,445
Service Quantity (times service provided)	175	178	180	180	180

Note: Service Quantities and revenues are actual for 2006, 2007 and 2008, with estimates for all future years. The information on actual revenues and quantities has been sourced from SAP.

19.20 Meter test

19.20.1 Service description

A customer or a retailer on behalf of a customer may request a meter test to verify that the meter is accurately measuring the energy consumption. This generally occurs after an electricity bill complaint by a customer. The current and proposed charges apply to all such testing. However, in the case of proven faulty meters, the charge is waived by JEN.

19.20.2 Current charges

Currently this service is provided at different charges depending on the type of meter tested and number of meters tests for a single customer. The current charges are set out in Table 19-21 below.

Table 19-24: Current Charges for Meter Testing

Current Service Name	Bus hrs	After hours
Single Phase – First meter	162.55	208.45
Single Phase – Second and subsequent meter	60.82	77.82
Multi Phase – First meter	244.36	312.27
Multi Phase – Second and subsequent meter	102.73	132.64

JEN does not expect these prices to change in 2010, as JEN's proposed changes to the price for this service would only come into effect in the forthcoming regulatory period.

As noted in section 19.5, which sets out the method for current charges, these charges were set in the 1990's and JEN has been unable to obtain the unit cost inputs used at the time.

19.20.3 Proposed control mechanism and charges

JEN proposes that, consistent with the current treatment of this service, the charges be controlled by way of price cap on the actual charge to the customer. JEN has proposed a single price for all meter testing, as the current underlying costs of testing various meters are similar.

Table 19-25, below provides indicative prices and X factors in accordance with the proposed control mechanism.

Table 19-25: Indicative prices for the forthcoming regulatory control period

Year	2011	2012	2013	2014	2015
Price – bus hrs ($ real 2010)	275.10	282.30	290.75	298.15	305.10
Price – after hrs ($ real 2010)	346.15	355.25	365.85	375.15	383.90
X (per cent)	-2.00%	-2.63%	-2.98%	-2.54%	-2.34%

The detailed assumptions and unit cost inputs used to build up the underlying costs for the proposed charges are provided in Appendix 16.

19.20.4 Service quantities and revenues

Table 19-26 below sets out the quantities and revenues for this service in the current regulatory period, with 2009 and 2010 figures being estimates.

Table 19-26: Quantities and revenues in the current regulatory control period

Year	2006	2007	2008	2009	2010
Revenue ($ real 2010)	31,058	30,311	30,103	28,675	28,318
Service Quantity (times service provided)	164	166	168	168	168

Note: Service Quantities are actual for 2008, with estimates for all future and past years. Historic quantities need to be estimated as, due to a change of ownership, JEN does not have access to detailed primary information on the number of services provided in 2006 and 2007 for this service. Revenues are estimated by multiplying current prices by estimated service quantities, as JEN's systems do not separately track revenues for this service.

19.21 Metering data provider services for unmetered supplies with type 7 metering installations

19.21.1 Service description

This service relates to the provision of metering data for unmetered supplies to street lights. The energy consumed by the unmetered streetlights is calculated in accordance with the metrology procedure.

19.21.2 Current charges

The current charge for this service is $0.128 per unmetered streetlight per year. JEN does not expect this charge to change in 2010, as JEN's proposed changes to the price for this service would only come into effect in the forthcoming regulatory period.

The method for current charges focuses on recovering the approximate cost to JEN of providing the service. JEN's identifiable costs of providing this service include an annual audit of the public lighting inventory table, as required by the metrology procedure for type 7 metering, as well as the costs of performing the meter data transfer to AEMO. These costs are spread over the population of streetlights connected via unmetered supplies. No unit costs are used in the calculation of the current charge.

19.21.3 Method for deriving proposed charge

In the absence of guidance from the AER and given the immaterial revenue from this service (approximately $8,000), JEN has adopted a top down approach for this service. JEN therefore proposes that the starting point for the indicative charge in 2011 should be the charge in 2010 adjusted by CPI.

The costs for this service have been specifically excluded from the scope of cost recovery and the regulatory framework for AIMRO. JEN's AIMRO charges application, as approved by the AER, did not include the recovery of the costs for this service, which are explained above. Also, as discussed in section 19.3, in calculating JEN's proposed base year standard control costs which are inputted into the AER's PTRM, JEN has explicitly removed the costs that related to alternative control services. Therefore, the costs of this ACS are not already compensated elsewhere.

Given the top-down approach, no indirect costs or overheads have been allocated to this service. Similarly, no shared assets have been allocated to the costs of providing this service.

JEN is not proposing to change the terms and conditions on which this service is provided in the current regulatory period.

19.21.4 Proposed control mechanism and charges

JEN proposes that the charges be controlled by way of price cap on the actual charge to the customer. Given the top-down approach adopted by JEN, the indicative starting price for 2011 would equal the price in 2010 (in real terms). JEN proposes that charges be adjusted each year by (1+CPI)(1-X), where X is equal to zero.

Table 19-27 below provides indicative prices and X factors in accordance with the proposed control mechanism.

Table 19-27: Indicative prices for the forthcoming regulatory control period

Year	2011	2012	2013	2014	2015
Price ($ real 2010) per unmetered streetlight per year	0.128	0.128	0.128	0.128	0.128
X (per cent)	-0.00%	-0.00%	-0.00%	-0.00%	-0.00%

19.21.5 Service quantities and revenues

Table 19-30 below sets out the quantities and revenues for this service in the current regulatory period, with 2009 and 2010 figures being estimates.

Table 19-28: Quantities and revenues in the current regulatory control period

Year	2006	2007	2008	2009	2010
Revenue ($ real 2010)	7,174	8,351	8,357	8,352	8,248
Service Quantity (number of unmetered streetlights)	63,749	64,271	64,442	64,442	64,442

Note: All service quantities and revenues are estimates, as JEN's systems do not separately track revenues and quantities for this service. Quantities are estimated based on the average number of street lights extracted from the annual Electricity Industry Comparative Performance report.

19.22 Recoverable works

19.22.1 Service description

Recoverable works services are services provided at the request of a customer that involve a time commitment from JEN and the costs of which vary, depending on the man-hours spent, the type of plant used and the type and amount of materials used in providing the service. JEN's proposed recoverable works ACS are as follows:

- damage to overhead service cables caused by high loads—restoration of overhead service cables pulled down by transport vehicles transporting high loads

- high load escorts—lifting of overhead lines

- supply abolishment—abolishment of existing supply

- rearrangement of network assets at customer request, excluding alteration and relocation of existing public lighting services

- supply enhancement at customer request—elective underground service where an existing overhead service exists

- location of underground cables—identification of underground electricity cables for persons planning to excavate in the vicinity of electricity underground cable.

19.22.2 Current charges

Given the nature of the recoverable works services, there are no specific charges or prices for these services. Under the current price determination, JEN applies a relevant labour rate, depending on the situation. JEN also on-charges at cost the materials used to provide recoverable works services. JEN will maintain this approach until the end of the current regulatory period,

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19.22.3 Proposed control mechanism and charges

JEN proposes that, consistent with the current treatment of this service, the charges be controlled by way of a price cap on the labour unit rate per hour, with materials and plant costs being passed onto customers at cost. The total charge to the customer would be quoted, prior to the service being provided. In Appendix 16, JEN has provided a bottom-up cost build up of what JEN believes to be a fully cost-reflective indicative labour rate that can be used as a starting point for the price cap in 2010.

Table 19-29 below provides indicative unit rates and X factors in accordance with the proposed control mechanism.

Table 19-29: Indicative prices for the forthcoming regulatory control period

Year	2011	2012	2013	2014	2015
Unit rate per man hr – business hours ($ real 2010)	94.05	96.55	99.20	101.80	104.25
Unit rate per man hr – after hours ($ real 2010)	122.30	125.50	128.95	132.30	135.50
X (per cent)	-2.43%	-2.63%	-2.73%	-2.63%	-2.43%

19.22.4 Service quantities and revenues

JEN's systems do not track the service quantities in relation to individual recoverable works services, or the services in aggregate. Likewise, revenues for individual recoverable works services are not tracked. However, revenues are tracked at the aggregate level.

Table 19-30 below sets out the revenues for recoverable works in the current regulatory period, with 2009 and 2010 figures being estimates.

Table 19-30: Revenues in the current regulatory control period

Year	2006	2007	2008	2009	2010
Revenue ($ real 2010)	393,860	19,216	103,953	99,020	97,787

Note: The information on actual revenues 2006-2008 has been sourced from SAP

JEN's systems do not record the time taken to complete each recoverable works service and JEN therefore cannot provide the mean and median time taken to complete each service in the current regulatory period.

19.23 Supply enhancement at customer request-reserve feeder

19.23.1 Service description

The reserve feeder service is a service provided to customers requesting an enhanced supply, by way of having a back-up connection to a feeder other than the one that the customer's primary connection relies on. In this way, should one feeder fail, the customer's supply will not be interrupted, but will be supplied through a reserve feeder.

19.23.2 Current charges

The current charge for this service differs from customer to customer, as individual contracts have been negotiated and signed with customers. While the service is currently treated as an excluded service, the ESC currently does not review or approve charges for this service, leaving it for the distributor to negotiate the price with the customer on a fair and reasonable basis.

With the exception of one customer (where a fixed per year fee is applied), JEN applies a per kW charge that is indexed by CPI. A summary of the charges for the current regulatory period for existing contracts is provided in Table 19-3 below.

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The method for current charges is to base charges on those set by the State Electricity Commission of Victoria (**SECV**) prior to 2000 in order to recover the ongoing costs to the business of providing the reserve feeder capacity. Up front capital costs are contributed by the customer. The charges differ slightly, depending on the timing of the contract being signed, which in turn affects the month of the year when the CPI adjustment is made and the specific CPI figures used for the adjustment.

The SECV methodology is simple and was designed to recoup ongoing costs incurred in the provision of reserve feeder supplies for customers requiring a significantly higher level of supply reliability.

19.23.3 Method for deriving proposed charge

JEN's proposed method for deriving charges for existing contracts is to use a top down approach, using existing prices and adjusting them by (1+CPI)(1-X). This is discussed in more detail in the next section.

Operating costs (including overheads) that relate to reserve feeder services and other ACS have been explicitly removed from the calculation of JEN's base year opex costs, consistent with JEN's proposed CAM, which ensures no double recovery of overheads. The explicit adjustment can be found in the forecast opex sheet (row 35) of the forecast data model.

JEN is not proposing to change the terms and conditions on which this service is provided in the current regulatory period.

19.23.4 Proposed control mechanism

JEN proposes that the charges for existing contracts for this service be regulated by way of a price cap, which would index existing prices by (1+CPI)(1-X), with X being equal to zero. The starting price for existing contracts would be prices as at the end of the current regulatory period. The starting price for new contracts would be the current predominant price of $15.20/kW per annum (in $2010 real as at 2011). The reason for providing the service on a different basis to existing customers is to honour pre-existing contractual agreements.

19.23.5 Indicative charges

Indicative charges for this service are set out in Table 19-32 below.

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19.23.6 Service quantities and revenues

Table 19-33 below sets out the quantities and revenues for this service in the current regulatory period, with 2009 and 2010 figures being estimates.

Table 19-33: Quantities and revenues in the current regulatory control period

Year	2006	2007	2008	2009	2010
Revenue ($ real 2010)	858,230	849,118	791,657	754,095	744,702
Service Quantity (customers)	16	16	16	17	17

Note: Service Quantities are actual for 2006, 2007 and 2008, with estimates for all future years. The information on actual revenues has been sourced from SAP

As this service is not provided by the man-hour, JEN does not possess information in relation to the mean and median time to complete the service in the current regulatory period.

19.24 Public lighting

This service relates to operation, repair, replacement and maintenance of distributors' existing public lighting assets.

In its framework and approach paper, the AER has stated that it will assess the efficient costs of the operation, repair, replacement and maintenance of public lighting assets under the price cap control mechanism through the use of a limited building block approach. The AER also noted that it would specify in the RIN the minimum building block information it expects DNSPs to provide in relation to public lighting assets.[75]

On 18 September 2009, the AER issued a draft public lighting model for consultation. JEN made a submission on the draft model on 16 October 2009. In the absence of further guidance from the AER until 10 November, JEN has, as a pragmatic measure, filled in the AER draft model without modification. The filled out model is attached (see Appendix 16) solely for the purposes of providing a demonstration of the application of the control mechanism, as set out in the framework and approach paper. JEN using the AER's draft model should not be seen as an endorsement of the model for the purposes of making a determination on JEN's public lighting costs or charges. JEN reserves the right to propose a different model in its tariff proposal.

Table 19-34 reproduces the tariffs that are produced by the AER's Draft Public Lighting Model.

[75] AER, *Framework and approach paper for Victorian electricity distribution regulation*, May 2009, p.79 to 80.

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It is important to note that the AER provided a final preferred public lighting model on 10 November 2009, 14 business days before JEN's regulatory proposal was required to be submitted. The model introduced new inputs that were not included in the draft model. In JEN's view it is reasonable to expect that more than 14 business days are required for JEN to evaluate the new model, obtain and verify the necessary source information, input the information into the model, update the regulatory proposal and the RIN templates for the output of that model, and obtain management and board sign-off of the amended regulatory proposal and RIN response.

Glossary

ABC	Aerial Bundle Cables
ABS	Australian Bureau of Statistics
ACR	automatic circuit re-closer
ACS	alternative control services
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGL	Australian Gas Light Company
AGLE	AGL Electricity Limited
ALARP	as low as reasonably practicable
AIMRO	Advanced Interval Metering Rollout
AMA	Asset Management Agreement between JEN and JAM
AMI	advanced metering infrastructure
ASIC	Australian Standard Industrial Classification
ATO	Australian Taxation Office
BGN	Bloomberg's generic yield
capex	Capital expenditure
CAPM	Sharpe-Lintner capital asset pricing model
CGS	Commonwealth Government Securities
CIS+	Customer Information System
COAG	Council of Australian Governments
COWP	Capital and Operating Plan
CPRS	Carbon Pollution Reduction Scheme

DAPR	Distribution annual planning report
DMIS	demand management incentive scheme
DMS	Distribution Management System
DNSPs	Distribution network service providers
DSES	Demand side engagement strategy
DUOS	Distribution use of system
EBSS	efficiency benefit sharing scheme
EGP	Eastern gas pipeline
EPA	Environmental Protection Authority
ESC	Essential Services Commission
ESF's	Enterprise support functions
ESMS	Electricity Safety Management Scheme
ETS	Emission trading scheme
EUCS	Energy Use and Conservation Survey
F&A Paper	AER's Framework and Approach Paper issued May 2009
FIG	Financial Investor Group
FYRAE	final year regulatory adjustment equation
GHGA	Greenhouse gas abatement
GIS	Geographic Information System
GSL	guaranteed service levels
HCD	Heating (cooling) degree day
HDD	Heating degree day
IMRO	Interval metering roll out
ITP	JEN's IT strategy and asset management plan

IVR	Interactive Voice Response
JAM	Jemena Asset Management
JEN	Jemena Electricity Networks (Vic) Ltd
LCM	life cycle management
LFS	Labour Force Survey
MAIFI	momentary average interruption frequency index
MAIFIe	momentary average interruption frequency index event
Marsh	Marsh Pty Ltd
MCE	Ministerial Council on Energy
MEPS	Minimum Energy Performance Standards
NAEEP	National Appliance Energy Efficiency Program
NAMP	JEN's Network Asset Management Plan
NCCF	National Customer Connection Framework
NECF	National Energy Customer Framework
NEL	National Electricity Law
NGERS	National Greenhouse and Energy Reporting Scheme
NIEIR	National Institute of Economic and Industry Research
NPDG	Network planning and development group
O&M	operating and maintenance
OESC	Office of the Emergency Services Commissioner
OIC	Order in Council
opex	Operating expenditure
PEG	Pacific Economists Group
PFIT	photovoltaic feed in tariff

POE	Probability of exceedence
PTRM	post tax revenue model
PwC	PricewaterhouseCoopers
QGP	Queensland gas pipeline
RAB	Regulatory Asset Base
RET	Renewable Energy Target
RFM	roll forward model
RIN	AER's Regulatory Information Notice issued to JEN on 13 October 2009
RIT-D	Regulatory investment test for distribution
ROLR	Retailer of last resort
Rules	National Electricity Rules
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCADA	SAP Works Management and Logistics, Supervisory Control and Data Acquisition
SFG	SFG Consulting
the Skeels Review	an independent review by Associate Professor Skeels of the SFG study
SKM	Sinclair Knight Mertz
SMS	Short Message Service
SORI	Statement of Regulatory Intent on WACC
SPI	Singapore Power International
SPIAA	SPI (Australia) Assets Pty Ltd
STPIS	service target performance incentive scheme

STT	Specification threshold test
SWER	Single Wire Earth Return
Synergies	Synergies Economic Consulting
TAB	tax asset base
TUOS	transmission use of system
UCMS	Aegis Services Australia
VCR	Value of customer reliability
VEEC	Victorian energy efficiency certificates
VEET	Victorian Energy Efficiency Target
WACC	Weighted Average Cost of Capital
WAPC	weighted average price cap
WOBCA	Whole of Business Cost Allocation