VENCorp

Victorian Energy Networks Corporation

VENCorp Electricity Revenue Cap Proposal 1 July 2008 to 30 June 2014

Mission

VENCorp ensures the efficient and effective delivery of energy for the benefit of the Victorian community

Vision

Victoria will achieve the most reliable and cost effective energy supply through competitive national markets

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Executive Summary

Background

VENCorp performs various statutory and non-statutory functions in the gas and electricity industries in Victoria. One of VENCorp's core functions is the provision of shared electricity transmission network services in Victoria. As the monopoly provider of these services VENCorp is subject to economic regulation under the National Electricity Rules (NER). It is required to submit to the Australian Energy Regulator (AER) forecasts of its statutory electricity transmission-related costs that are expected to be recovered through Transmission Use of System (TUoS) charges over the relevant regulatory period commencing 1 July 2008.

This application sets out all necessary information required by the AER to determine the revenue cap that will apply to VENCorp for forthcoming regulatory period.

As the Transmission Network Service Provider (TNSP) responsible for directing augmentations to Victoria's electricity transmission network VENCorp's primary driver is to ensure the long-term reliability and adequacy of the transmission network. VENCorp also provides transmission services under Use of System Agreements.

Electricity transmission network planning is conducted on an economic basis using the market benefits limb of the regulatory test. This ensures that the services procured by VENCorp are the most efficient and value maximising for Victorian electricity consumers.

The ownership, governance and organisational arrangements within the Victorian electricity transmission sector are unique insofar that VENCorp:

- is the only TNSP in Australia which is constituted as a not-for-profit organisation;
- does not own any transmission assets;
- has corporate objectives explicitly requiring that it deliver its services, and to perform its functions, in a commercially-neutral and cost-effective (value-maximising) manner; and
- is required to competitively tender for transmission services which exceed a pre-defined value.

Chapter 9 of the NER explicitly recognises and accommodates these arrangements.

VENCorp's cost structure

VENCorp recovers the costs associated with its statutory electricity transmission-related functions through TUoS charges. Over the regulatory period these costs will consist of the following elements:

- VENCorp's operating and planning costs;
- payments made by VENCorp to providers of new augmentations that will be required over the relevant regulatory period to maintain adequate levels of transmission system reliability and performance (*planned augmentation charges*);
- payments made by VENCorp to transmission asset owners for bulk transmission services provided under existing contracts won under the competitive tendering arrangements or where otherwise directed by VENCorp (*committed augmentation charges*); and
- payments made by VENCorp to SP AusNet and Australian Pipeline Trust for the provision of prescribed transmission services, which are subject to separate regulation by the AER (*prescribed service charges*).

Relevant regulatory period

At the request of the AER VENCorp has submitted its revenue proposal at the same time as SP AusNet to facilitate the AER's preparation of a revenue determination for the Victorian electricity transmission network. Therefore, the information presented in this revenue proposal is for the six year period from 1 July 2008 to 30 June 2014.

Key features of this application

Operating and Planning Expenditure

VENCorp's operating and planning expenditure constitutes less than 2 per cent of transmission network charges in Victoria, which equates to approximately 0.1 per cent of total delivered electricity costs to end use customers.

With the exception of labour costs, which are forecast to grow at 4.5 per cent per annum, VENCorp is forecasting operating and planning expenditure to increase by 3 per cent per annum which is in line with inflationary expectations. Table E1 sets out VENCorp's forecast operating and planning expenditure.

Table E1 – Forecast Operating and Planning Expenditure

	$(millions) nominal excluding GST					
	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Operating and Planning Expenditure	6.7	7.0	7.2	7.5	7.7	8.0

Planned Augmentation Charges

In total VENCorp is forecasting $354 million of new augmentations, in real terms, will need to be assessed against the regulatory test over the forthcoming regulatory period to maintain adequate reliability levels on the Victorian transmission network. This compares with around $140 million of augmentations assessed against the regulatory test over the current regulatory period.

This increase in augmentation requirements is driven by three factors:

- the increase in the relevant regulatory period from five years to six years;
- the increasing cost of augmentations driven by global demand for network assets; and
- the nature of the supply-demand balance over the regulatory period in Victoria driving the need for new generation which will in turn drive augmentation expenditure.

Table E2 sets out VENCorp's planned augmentation charges for the relevant regulatory period.

Table E2 –Planned Augmentation Charges

	$(millions) nominal excluding GST					
	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Planned Augmentation charges	0.2	1.7	6.8	15.8	31.8	43.0

Committed Augmentation Charges

The committed augmentation charges set out payments for shared transmission services provided under contracts won or directed prior to regulation under the NER and those won or directed during the current regulatory period such as the installation of two new transformers at Rowville and Moorabool and the up-rating of the transmission line from the La Trobe Valley to Melbourne.

Table E3 sets out the committed charges for the forthcoming regulatory period.

Table E3 – Committed Augmentation Charges

	$(millions) nominal excluding GST					
	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Committed Augmentation charges	22.9	23.6	24.3	25.0	25.7	26.5

Prescribed Service Charges

The prescribed services charges are based on information supplied by SP AusNet to VENCorp in line with its revenue proposal submitted to the AER, the AER's revenue cap decision for the Murraylink interconnector of 1 October 2003 and includes an allowance of $6 million for the Availability Incentive Scheme.[1]

Table E4 sets out the prescribed service charges.

1 Australian Energy Regulator, Murraylink Transmission Company Application for Conversion and Maximum Allowed Revenue, 1 October 2003,

Table E4 – Prescribed Services Charges

	$(millions) nominal excluding GST					
	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Prescribed Service charges	376	399.5	424.6	451.2	479.5	509.7

Based on the above components VENCorp's estimated total revenue requirement for the period ending 30 June 2014 is set out in Table E5.

Table E5 – Total Revenue Requirement

	$(millions) nominal excluding GST					
	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Operational Expenditure	6.7	7.0	7.2	7.5	7.7	8.0
Planned Augmentation charges	0.2	1.7	6.8	15.8	31.8	43.0
Committed Augmentation charges	22.9	23.6	24.3	25.0	25.7	26.5
Total forecast expenditure for VENCorp	29.8	32.2	38.3	48.3	65.3	77.5
Prescribed Services charges	376	399.5	424.6	451.2	479.5	509.7
Total Revenue Requirement*	404.7	430.8	461.8	498.5	543.8	586.2
*Energy (GWh)***	52,350	51,673	51,668	51,807	52,781	53,383
Victorian TUoS charges ($/MWh)	7.7	8.3	8.9	9.6	10.3	11.0

* - Total Revenue Requirement has been reduced by $1 million per annum to account for interest income earned by VENCorp

**- The energy value is on a generator sent out basis.

1 Introduction

VENCorp is constituted as a not-for-profit Transmission Network Service Provider (TNSP) and performs various statutory and non-statutory functions in the gas and electricity industries in Victoria. One of its core statutory functions is the provision of shared electricity transmission network services in Victoria. As the monopoly provider of these services, VENCorp is subject to economic regulation under the National Electricity Rules (NER). As such it is required to submit forecasts of its statutory electricity transmission-related costs that it expects to incur over the relevant regulatory period which it will recover through Transmission Use of System (TUoS) charges.

The applicable provisions relating to the setting of VENCorp's Maximum Allowable Aggregate Revenue (MAAR) are set out in Chapters 6 and 9 of the NER. In particular, Chapter 9 Part A – Jurisdictional Derogation for Victoria explicitly recognises and accommodates the unique organisational arrangements that exist within Victoria's electricity transmission sector. As such, the NER requires VENCorp's revenues to be determined in accordance with the following principles:

- the amount of VENCorp's MAAR for a relevant regulatory period must not exceed VENCorp's statutory electricity transmission-related costs; and

- VENCorp's MAAR must be determined on a full cost recovery but no operating surplus basis[2].

The NER requires that the AER set VENCorp's MAAR in accordance with these principles.

VENCorp's statutory electricity transmission-related costs are defined in Chapter 9 Part A – Jurisdictional Derogation for Victoria, as the sum of the following costs for a relevant regulatory period:

- VENCorp's aggregate actual costs in operating and planning the Victorian Transmission Network;

- all network charges payable by VENCorp to SPI PowerNet or any other owner of the Victorian Transmission Network or a part of the Victorian Transmission Network, including charges relating to augmentations;

- all other charges payable by VENCorp to providers of network support services and other services which VENCorp uses to provide network services that are transmission services; and

- any other costs that directly arise out of VENCorp's functions under the Electricity Industry Act relating to the transmission of electricity, the application of the NER to VENCorp or the conditions imposed on VENCorp under its transmission licence relating to the transmission of electricity, for which there is no alternative method (legislative or contractual) for the recovery of those costs.[3]

VENCorp's revenue proposal to the AER must set out the following:

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2 National Electricity Rules, Chapter 9 Part A – Jurisdictional Derogation for Victoria, Clause 9.8.4C

3 National Electricity Rules, Chapter 9 Part A – Jurisdictional Derogation for Victoria, Clause 9.3

- its proposed maximum allowable aggregate revenue for each financial year in that relevant regulatory period;
- its forecast statutory electricity transmission-related costs for each financial year in that relevant regulatory period; and
- a statement reconciling its most recent forecast of:
    - the revenue that will be recovered by way of shared transmission network use charges; and
    - the statutory electricity transmission-related costs, for the relevant regulatory period immediately preceding the relevant regulatory period to which the application relates.

This revenue proposal provides all necessary information required by the AER to determine the MAAR that will apply to VENCorp for the relevant regulatory period commencing 1 July 2008.

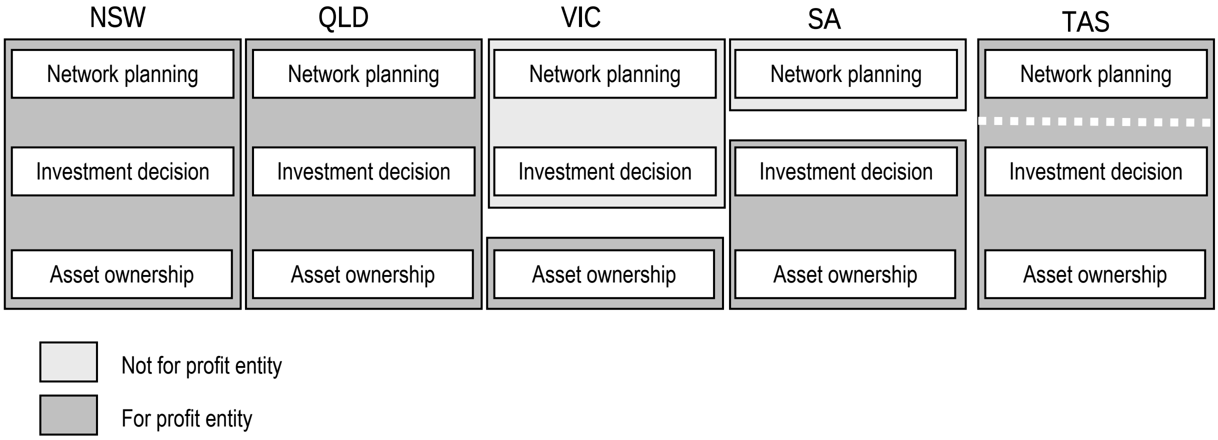
2 VENCorp's roles and functions

2.1 Victoria's unique electricity transmission arrangements

The ownership, governance and organisational arrangements within the Victorian transmission sector are unique insofar that VENCorp is the only TNSP in Australia which is constituted as a not-for-profit organisation which does not own any transmission network assets. Its role is that of an independent transmission network planner and investment decision maker.

In contrast, investment decision making and asset ownership is undertaken by one organisation throughout the rest of the NEM as shown in Figure 2.1.

Figure 2.1 – Structural separation of network planning and asset ownership



Source: Firecone, "A report to the Department of Infrastructure Victoria", August 2006

VENCorp considers that these structural differences and its governance arrangements, discussed in section 2.3, which include independent directors should, of themselves, provide the AER and other stakeholders with a considerable degree of comfort that:

- the operating costs incurred by VENCorp in undertaking its network service provision, network planning and related functions are efficient;
- the transmission investment decisions made by VENCorp are efficient and effective, particularly as:
    - o VENCorp is the only TNSP in the NEM who applies the market benefits limb of the AER's regulatory test; and
    - o it does not have a regulated asset base it does not have an incentive to construct network investments over alternative options such as demand side or grid support; and
- given the opportunities for increased competition for construction and ownership of new transmission assets through the competitive tendering provisions, the costs of assets that are created pursuant to a VENCorp investment decision reflect efficient practices.

Further, under these arrangements ***all*** efficiency gains achieved as a result of the independent planning are returned to consumers via reduced TUoS charges.

2.2 VENCorp and the energy industry

VENCorp's statutory electricity transmission-related functions are:

- to plan and direct the expansion of the shared transmission network in an economic manner consistent with market reliability requirements and expectations;
- to procure 'bulk' transmission network services from asset owners consistent with the above;
- to advise and liaise with the National Electricity Market Management Company (NEMMCO) on network constraints, including interconnection transfer limits;
- to provide shared transmission network services to network users for a price in accordance with the NER and AER requirements;
- to monitor and report on the technical compliance of connected parties to the shared transmission network in terms of quality of supply and control systems, and provide power system data and models to NEMMCO;
- to participate in market development activities in the areas that affect VENCorp's functions;
- to assist in managing an electricity emergency by liaising between the government and NEMMCO, and communicating with the Victorian industry and community both before and during an emergency; and
- to provide information and support to the Victorian Government.

VENCorp also performs a number of important roles and functions in Victoria's gas market including:

- independent system operator for the Victorian gas transmission network;
- manager and developer of the Victorian wholesale gas market;
- transmission infrastructure planner for the gas industry; and
- facilitator of gas Full Retail Contestability (FRC) functions in Victoria and Queensland.

There is a number of legislative, regulatory and contractual instruments that define VENCorp's role, functions and powers as the planner and monopoly provider of shared electricity transmission network services. These instruments include:

- the Electricity Industry Act;
- VENCorp's Electricity Transmission Licence;
- the National Electricity Rules;
- the Victorian System Code; and

- Use of System Agreements between VENCorp and transmission network users.

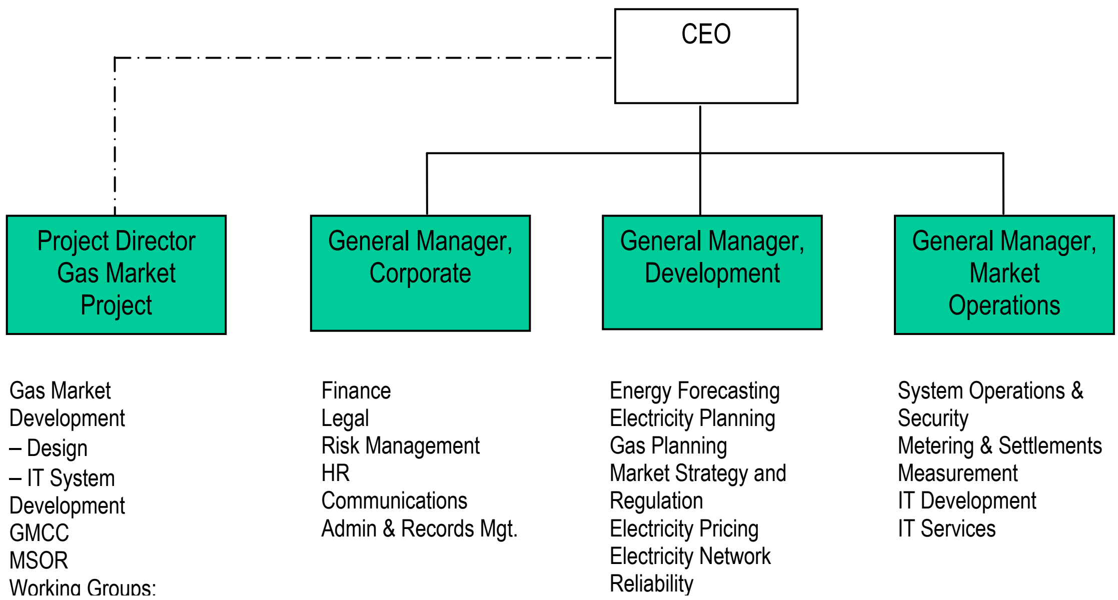
Attachment 1 provides a summary of the relevant provisions contained in these instruments.

2.3 VENCorp's Governance arrangements

VENCorp is wholly owned by the Government of Victoria and is responsible to the Minister for Energy and Resources. The organisation has a Board of 10 directors who oversee governance and approves the organisation's strategic direction.

VENCorp's day-to-day operations are overseen by the Chief Executive Officer (CEO) who reports to the VENCorp Board. The organisation is managed by an Executive Team comprising General Managers and, in the case of the Gas Market Project, a Project Director. The Executives set, monitor and review VENCorp's various operations and functions. This is outlined in Figure 2.2.

Figure 2.2 – Structural separation of network planning and asset ownership



The Corporate Governance practices of VENCorp actively encourage high standards of accountability in the delivery of its services. During this regulatory control period the Board reviewed its Corporate Governance Guide and Terms of Reference for all Committees. VENCorp has an established Code of Conduct that articulates standards of behaviour for both personal conduct and business practices.

The Board has a number of Directors drawn from participants in the gas and electricity industries, providing knowledge and experience, balanced with independent directors. All directors act impartially in VENCorp's best interests.

The Board approves VENCorp's goals and directions, considers strategic plans, approves performance targets and provides overall policy guidance. The Board ensures that appropriate policies, procedures and associated internal controls are in place to manage risks. Board meetings are generally held monthly. The Board has established four committees to assist it to carry out its duties:

- the Audit and Risk Committee;
- the Remuneration Committee;
- the Safety and Emergency Management Committee and
- the Policy Development Committee.

The Audit and Risk Committee assesses and reviews the internal and external audits and is responsible for assessing the adequacy of VENCorp's accounting, financial and operating controls. The Committee recommends the appointment of the internal auditors, the scope of the audit and the setting of fees, and also oversees the Market Operations Audit. The Committee reviews VENCorp's compliance with the legislation, rules and codes governing the operations of the organisation and monitors the risk management framework policy, guidelines and controls implemented under the risk management system. It also oversees risk identification and ensures that VENCorp develops and maintains a successful risk management system which is appropriate for an organisation of VENCorp's regulatory and operating environments.

The Remuneration Committee ensures that best practice approaches and approved procedures for the determination of remuneration for its senior executives are applied in line with Victorian Government Policy. The Committee provides to the VENCorp Board, quality assurance relating to the integrity and probity of VENCorp's remuneration policies and practices.

The Safety and Emergency Management Committee ensures that VENCorp has the necessary programmes and processes in place to fulfill its responsibilities for safety and management of emergencies within the gas and electricity industries. It also ensures that VENCorp observes its statutory compliance with safety regulations.

The Policy Development Committee provides the VENCorp Board with strategic advice and recommendations in regard to both gas and electricity market development. The Committee also reviews the service levels provided to participants.

2.4 Strategic Core Drivers

As VENCorp is funded in total by the industries it serves, it needs to maintain a commercial focus on its strategic imperatives of service, budget control, reliability of systems, security, and parity in the treatment of industry participants. VENCorp's Strategic Core Drivers reflect VENCorp's corporate values and are necessary to fulfilling the vision and mission of the organisation.

Its four core drivers are:

(1) *Our People*: VENCorp is committed to ensuring that its people are provided with the resources and capabilities to deliver the best possible service to its many energy industry stakeholders and seeks to create an environment where staff optimise their skills, capabilities, values and behaviours to contribute to VENCorp's organisational objectives.

(2) *Sound Commercial Management*: VENCorp is a commercially responsible organisation that implements best-practice budget and cost control processes in all areas, including project and contract management.

(3) *Stakeholder Value*: VENCorp recognises its responsibility to key stakeholders and aims to ensure that all services are appropriately costed, delivered on time and to the required quality level.

(4) *Reliable Systems*: VENCorp aims to meet energy demand safely without supply or market disruption due to system failures or inadequacies. In this instance, reliable "systems" includes the electricity and gas transmission systems and the various IT systems and procedures implemented and maintained by VENCorp to fulfil its functions and interact with other industry participants.

VENCorp's Strategic Core Drivers were formulated with the following in mind:

- The need to consolidate and enhance its reputation and to cement positive relationships with its stakeholders and customers;
- The emerging needs of a world class marketplace, and the demands and needs of the markets in which VENCorp currently operates; and
- The emerging needs of the energy sector over the coming five years.

2.5 Governance arrangements for approval of augmentations

To ensure the efficient identification and effective delivery of augmentations for the Victorian transmission system VENCorp follows a six step process:

(1) Planning and project identification;
(2) Project approval;
(3) Procurement;
(4) Contract Negotiation;
(5) Project Monitoring; and
(6) Reporting.

Each of these steps is discussed in turn.

Planning and project Identification – In accordance with its requirements under the NER VENCorp undertakes an annual planning review, the outcome of which is the Electricity Annual Planning Report (EAPR). This process is audited as part of VENCorp's Internal Audit Program and was last audited in 2006.

Through this process it will identify network constraints and potential options to address these constraints. All options, irrespective of its projected capital cost, is subjected to detailed economic analysis in accordance with the requirements of the market benefits limb of the regulatory test.

VENCorp assess these constraints using the criteria and approach set out in its Electricity Planning Criteria document, which is discussed in section 4.1.

VENCorp's Project Framework involves development of a project plan and a risk assessment of the impact of the project. The project plan is approved by the Project Manager and General Manager. All of VENCorp's risks are assessed using VENCorp Risk Matrix in accordance with VENCorp's Risk Management Guidelines and are reviewed by VENCorp's Risk Manager.

Once a project has internal management approval, a regulatory test process can then commence prior to obtaining CEO and Board approval for the project to proceed.

Project Approval - Once a project has satisfied the requirements of the regulatory test approval to proceed with the project is obtained from either the CEO or the Board. VENCorp's CEO can approve projects of up to $1 million. Above this quantum, Board approval is required. The CEO and Board approve the Terms and Conditions of the project. In all cases the Board is informed of all significant projects undertaken regardless of cost.

Board approval is documented via Board Meeting minutes.

The financial delegations are given in VENCorp's Deed of Delegations document.

Procurement - Transmission network augmentations may involve contestable and non-contestable works. The ESC Guidelines No. 18 determine what is and what is not contestable works.[4]

Once approval is given VENCorp will tender for contestable works in line with that specified in the ESC Guidelines for items over $10 million.

For high risk or high cost projects, a Steering Committee is set up to oversee the process of risk review, awarding of Tender and Procurement. The Steering Committee is generally made up of Senior Management representatives.

VENCorp has a Tendering Policy and Procedure which ensures a fair and consistent approach is applied in accepting and evaluating all Tenders. This is checked via the Probity Plan which must be completed and is checked by a Probity Auditor. Depending on the Tender, the Probity Auditor may be external to VENCorp.

Contract Negotiation - VENCorp will negotiate a Contract of Services for contestable works around terms and conditions approved by the Board. VENCorp has set contract Terms and Conditions which are the base of any contract/agreements and all contracts/agreements are subject to legal review. These contracts are signed by the CEO with Board approval.

For non-contestable works, VENCorp will enter into a Network Agreement with SP AusNet. This Network Agreement is subject to legal review prior to sign off by the CEO with Board approval.

Contract/Project Monitoring - There are regular meetings with the Contract parties to monitor progress and discuss issues. These meetings are minuted and copies circulated to the project parties.

4 The objective of ESC Guidelines No 18 is to facilitate competition in the construction, operation and maintenance of augmentations of the electricity transmission system and, in particular to make provision for the classification and treatment of certain augmentations contestable augmentations.

VENCorp is close to finalising a preferred supplier of a Contract Management system to further assist VENCorp manage its obligations and those of third parties under contract. Final approval and sign off by CEO is required.

Reporting - Once a project is underway, regular reports are provided to VENCorp's Board on project progress via a separate monthly report to the Board for significant projects or via the monthly CEO report.

The Board receives a Monthly Risk Management Summary which is a review of the status of VENCorp's risks, including project risks, with a Critical or Significant residual risk rating.

2.6 VENCorp Statutory Review

The Allen Consulting Group (ACG) was engaged by the Victorian Department of Infrastructure, now subsumed within the Department of Primary Industries (DPI) to undertake a review of VENCorp as prescribed by Section 205 of the Gas Industry Act to determine the value of the functions currently performed by VENCorp and to identify any additional functions that should be vested with VENCorp.

Overall ACG's review found that the Victorian energy industry and the community valued VENCorp's key current function and it was considered to undertake these functions effectively and efficiently and to a high standard. There was also strong support for the separation of transmission asset planning and ownership by a number of respondents.

In its review ACG also noted that the Victorian electricity transmission arrangements could be expected to deliver superior outcomes to regulation of for-profit entities:

> While direct regulation of for-profit entities' transmission planning decisions may deliver acceptable outcomes (depending on the effectiveness of that regulation), assigning this task instead to an entity that is specifically designed to make public interest decisions could be expected to deliver superior outcomes. Moreover, we consider this reliance on directing TNSPs to act in the public interest – rather than trying to provide for-profit entities with financial incentives to plan and invest optimally – is inevitable given the interdependencies between all elements of electricity systems, the nature of transmission investment and the considerable public interest elements associated with a reliable and secure electricity supply. We also note in this regard the widely held view amongst Victorian industry participants that VENCorp is performing these functions to a high standard. [5]

The AGC report is available from the DPI website.

[5] Allens Consulting Group, Statutory Review of the Victorian Energy Networks Corporation: Final Report, p vi.

3 VENCorp and the NER

3.1 The Victorian derogation

As noted in the introduction Chapter 9 Part A – Jurisdictional Derogation for Victoria explicitly recognises and accommodates the unique organisational arrangements that exist within Victoria's electricity transmission sector. As noted previously, the key features and principles that underpin the Victorian regime are as follows:

- the amount of VENCorp's MAAR for a relevant regulatory period must not exceed VENCorp's statutory electricity transmission-related costs; and
- VENCorp's MAAR must be determined on a full cost recovery but no operating surplus basis[6].

VENCorp's statutory electricity transmission-related functions consist of the following:

- VENCorp's operating and planning costs;
- payments made by VENCorp to providers of new augmentations that will be required over the relevant regulatory period to maintain adequate levels of transmission system reliability and performance (*planned augmentation charges*);
- payments made by VENCorp to SP transmission asset owners for bulk transmission services provided under existing contracts won under the competitive tendering arrangements or where otherwise directed by VENCorp (*committed augmentation charges*); and
- payments made by VENCorp to SP AusNet and Murraylink for the provision of prescribed transmission services, which are subject to separate regulation by the AER (*prescribed service charges*).

Attachment 2 sets out the relevant provisions of the Victorian derogation.

3.2 Relevant regulatory period

The arrangements setting out when VENCorp should submit its revenue proposal is set out in clause 9.8.4C(b) which states:

> (b) Not less than 7 months before the commencement of a relevant regulatory period, VENCorp must, for the purpose of enabling the AER to determine VENCorp's maximum allowable aggregate revenue for a relevant regulatory period, submit its revenue application for that relevant regulatory period to the AER that sets out:

However, at the request of the AER VENCorp has agreed to submit its revenue proposal by 28 February 2007 for a six year period to align with SP AusNet's submission and facilitate the AER's preparation of a revenue determination for the Victorian transmission network. Therefore, the information presented in this revenue proposal is for a six year period from 1 July 2008 to 30 June 2014.

[6] National Electricity Rules, Chapter 9, Part A, clause 9.8.4F

3.3 Amendments to the National Electricity Rules

On 16 November 2006 and 21 December 2006 the AEMC released its determinations on transmission revenue and transmission pricing rules amending Chapter 6 of the NER. These amendments introduced Chapter 6A into the NER, which replaces the rules for the economic regulation of transmission services previously contained in Chapter 6 of the NER.

The changes to the NER replace VENCorp's revenue cap application with a requirement to submit the following three proposals for approval as part of a transmission determination:

- a revenue proposal (which replaces the concept of a revenue cap application);
- a proposed pricing methodology (which largely replaces the previous rules for determining prescribed transmission service charges and prices); and
- a proposed negotiating framework (which is broadly similar to that required to be established under the previous rules obliging TNSPs to establish a negotiating framework).

Revenue Proposal

In submitting its revenue proposal, VENCorp must also submit information in accordance with the draft submission guidelines. The key requirements in the proposed submission guidelines relevant to VENCorp include:

- the revenue proposal must be based on accounting principles and policies for which there is a recognisable and rational economic basis and which produce relevant and reliable information, ensuring fair reporting of the substance of underlying transactions;
- full and detailed documentation of the financial and regulatory accounting principles and policies used to prepare the proposal must be given to the AER;
- any changes to the accounting principles and policies from those previously adopted, and the reasons for such changes, must be brought to the AER's attention (including where applicable the quantified impact of the changes on the regulatory information);
- all material items must be disclosed (an item is material if its omission, mis-statement or non disclosure may prejudice the understanding of the financial or operational position and nature of the prescribed transmission services);
- all information provided must be verifiable (ie. traceable by an independent party to a source document or assumption);
- VENCorp should maintain accounting and reporting arrangements that enable separate regulatory information to be prepared for submission to the AER;
- the AER may require VENCorp to have information in the revenue proposal independently audited; and
- the revenue proposal must be accompanied by a Directors' responsibility statement (example form set out in Appendix B to the AER's proposed submission guidelines).

In allocating costs between categories of transmission services (prescribed or negotiated), VENCorp must comply with a cost allocation methodology approved by the AER. Until the approval of that methodology, VENCorp must allocate costs in accordance with proposed cost allocation guidelines to be published by the AER.

VENCorp has complied with these requirements to the extent that they are applicable.

Pricing Methodology

As under the old regime, VENCorp remains the coordinating TNSP responsible for allocating the applicable part of the SP AusNet and VENCorp revenue requirements within the Victorian region (the revenue requirements so allocated are used to determine prices for prescribed TUOS services and prescribed common services). The provisions relating to VENCorp as coordinating TNSP are substantially the same under the new regime, except for additional requirements for the provision of information between VENCorp and SP AusNet.

Under Chapter 6A of the NER, a TNSP's aggregate annual revenue requirement must be allocated in accordance with a pricing methodology approved by the AER as part of that TNSP's transmission determination. A TNSP's proposed pricing methodology must:

- give effect to and be consistent with the pricing principles for prescribed transmission services set out in clause 6A.23; and
- comply with the requirements of, and contain or be accompanied by such information as is required by, the pricing methodology guidelines made by the AER.

The requirements described above are subject to the application of the provisions of the Victorian transmission pricing derogations contained in clause 9.8.4F

The AER is required to make the first pricing methodology guidelines by 31 October 2007. However, transitional provisions require that, for the purposes of VENCorp's, SP AusNet's and ElectraNet's revenue resets, interim requirements must be agreed by the AER with these TNSPs. These interim requirements must comply with the requirements for pricing methodology guidelines in clause 6A.25 – in particular they must be consistent with the pricing principles contained in clause 6A.23 and must address the content requirements set out in clause 6A.25.2.

Following discussion with the AER, VENCorp has agreed to submit its pricing methodology by no later than 31 May 2007.

Negotiating Framework

From the commencement of the next regulatory period, when negotiating with an applicant for the provision of negotiated transmission services, VENCorp must comply with an AER-approved negotiating framework and negotiated transmission services criteria that are determined by the AER consistently with the negotiated transmission services principles which are set out in clause 6A.9.1.

For these purposes, VENCorp must submit a proposed negotiating framework to the AER. This negotiating framework must be consistent with the AER's proposed submission guidelines published on 31 January 2007 and must also comply with the requirements of clause 6A.9.5.

Attachment 3 sets out VENCorp's negotiating framework

3.4 National Energy Market Reforms

There are many changes taking place in the energy industry which may change VENCorp's roles and functions in the energy market. In electricity the recommendations of the Energy Reform Implementation Group may see the creation of a national transmission planner. Similarly the gas market is undergoing significant changes with the development of the National Gas Market in line with the recommendations of the Gas Market Leaders Group which are being recognised in the amendments to the National Gas Law and National Gas Rules.

Despite these proposals this revenue proposal is being put forward to the AER on the basis of 'business as usual'.

4 VENCorp's approach to transmission planning

The manner in which VENCorp undertakes its electricity transmission planning to meet is statutory obligations are set out in two key documents: its Electricity Planning Criteria and the Connection Augmentation Guidelines. How VENCorp uses these documents is evident in its Electricity Annual Planning Reports (EAPR) and Vision 2030 documents. A summary of each and its relevance to this revenue proposal is set out in sections 4.1 to 4.4.

4.1 Electricity Planning Criteria

VENCorp undertakes its planning to meet system performance standards and system security requirements in accordance NER and the Victorian Electricity System Code. The system performance standards define the technical limitations of the system, for example: voltage ranges, stability limits, maximum fault currents, and fault clearance requirements. These standards ensure that assets connected to the power system, or those that constitute the power system, are designed to operate within known technical limits.

Consistent with these requirements, VENCorp's transmission network planning is aimed at ensuring that, following the loss of the most critical transmission element, including at times of peak demand:

- the security of the power system can be maintained;
- transmission plant ratings are not exceeded; and
- the network performance requirements in Schedule 5.1 of the National Electricity Rules are met.

To satisfy these requirements, VENCorp accepts the possibility of load shedding due to an event but includes the expected unserved energy in the cost-benefit analysis, which is used to determine the optimum solution and implementation timing for an augmentation. This involves investment decisions based on a probabilistic analysis of energy at risk, which includes consideration of the probability-weighted impacts on supply reliability of low probability high cost events.

VENCorp's planning approach is aimed at ensuring that these system security and performance obligations will continue to be fulfilled in the most economic way using the market benefits limb of the regulatory test. [7]

Undertaking this assessment requires three components of the power system to be analysed:

- the market;
- the network; and

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[7] The market benefits limb of the regulatory test is:

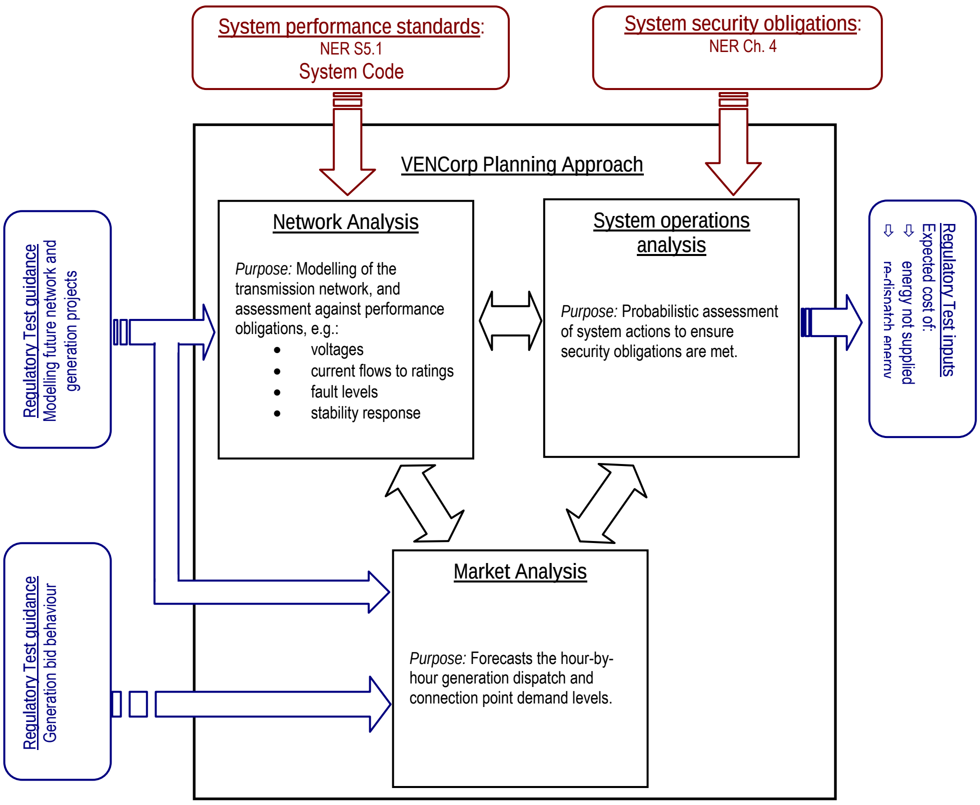
(1) An option satisfies the *regulatory test* if:

(b) in all other cases - the option maximises the expected net present value of the *market benefit* (or in other words the present value of the *market benefit* less the present value of *costs*) compared with a number of *alternative options* and timings, in a majority of *reasonable scenarios*.

- system operations.

These three components and the interactions with each other and the obligations are shown in Figure 4.1.

Figure 4.1 –Overview of VENCorp Planning Approach



This document is the key input into how committed augmentation expenditure, and therefore committed augmentation charges, have been determined and will be used to determine actual charges going forward. Each option to address a constraint identified as part of the planned augmentation program will be assessed using the approach outlined in the Electricity Planning Criteria.

4.2 Connection Augmentation Guidelines

The NER sets out the processes and procedures that Network Service Providers (NSPs) and connection applicants must follow when a new connection to the transmission network is sought. Depending on the size, scope, timing and location of a new connection network augmentations may be required to facilitate connection to the network.

Connection augmentations may be required for one of two reasons:

- to ensure that a new connection complies with the NER's specified access standards for connection to the network (access augmentations); or

- to provide sufficient power transfer capability to meet the new connection's requirements (power transfer augmentations).

As the NSP responsible in Victoria for augmentations to the shared transmission network, VENCorp must assess and advise on issues associated with any augmentations to facilitate network connections.

While the NER sets out the processes for the consideration of technical matters during a connection process and enables a connection applicant to request a level of power transfer capability that is higher than the network's existing power transfer capability, it does not expressly address the issues of who should pay for augmentations to facilitate the network connection and how these costs are to be allocated between network users and the connection applicant.

As a result in August 2005 VENCorp developed and released Connection Augmentation Guidelines.

The Connection Augmentation Guidelines state that where it is identified that an augmentation is required to comply with a NER specified access standard, the connection applicant will be required to fund that augmentation in accordance with the requirements of the funded augmentation provisions of the NER. Augmentations required to increase the power transfer capability of the network could be funded by a new connection applicant, however, these augmentations may also be subjected to a regulatory test assessment.

In line with these principles no allowance has been made for augmentations which may be required to facilitate the connection of a new generator or load have not been included in this revenue proposal. These will be paid for by the individual connection applicants at the time of their connection in line with the funded augmentation provisions of the NER.

4.3 Annual Planning Report

Clause 5.6.2A of the NER requires VENCorp to undertake an annual planning review and publish an EAPR by 30 June each year, setting out:

- the forecast loads submitted by Distribution Network Service Providers;
- planning proposals for future connection points[8];
- a forecast of constraints and inability to meet network performance requirements; and
- detailed analysis of all proposed augmentations to the network.

Given VENCorp's functions and the planning responsibilities of the Victorian distribution businesses, and NEMMCO, the scope of VENCorp's EAPR is confined to assessing the adequacy of the Victorian shared transmission network to meet Victorian load growth over the 10 years horizon. The EAPR

[8] The adequacy and reliability of the distribution networks, which are owned, operated, maintained and planned by the distribution businesses, have not been considered in this document. These issues are subject to oversight by the ESC. Distribution businesses are also responsible for the planning of the transmission connection assets from which they take supply, and they publish a connection asset planning document (in accordance with obligations set out in their distribution licences) that is available on their specific websites.

does not define a specific future development plan for the shared network, rather, it is intended to be a key step in the provision of an economically optimum level of transmission system capacity.

As noted previously, through this process it will identify network constraints and potential options to address these constraints. These options are assessed against the regulatory test using the approach outlined in the Electricity Planning Criteria document. As per the requirements of the NER, new small and minor transmission network assets are subject to public consultation in the EAPR while new large transmission assets are subject to more detailed public consultation processes.

4.4 Vision 2030

In 2005 VENCorp released Vision 2030. Vision 2030 outlines a 25 year vision for Victoria's core energy transmission infrastructure and the potential requirements for investment in new transmission capacity to meet the State's needs over the period. It comprises a series of individual development paths for each of the key elements corridors of transmission infrastructure serving Victoria's energy markets.

The actual transmission outcome in 2030 will be determined by industry and market developments over the next 25 years. However, any outcome is highly likely to be based on a subset of the transmission augmentation projects identified in Vision 2030

In preparing Vision 2030 twenty-one factors were identified and assessed as influencing investments in transmission infrastructure. The factors are listed in Table 4.1.

Table 4.1 – Factors that shape investment in new infrastructure

Energy demand	Energy supply	Authorising environment	Key resources
• Population trends • Lifestyle trends • Smelter load • Gas fuelled power generation gas demand • Other commercial and industrial demand • End-use technologies	• Fuel location and price • Old plant retirement • Supply technology • Investment climate • Energy market prices	• Carbon emissions policy • Competition policy • Regulation of transmission investment • Independent network planning • Security/reliability policy • Renewable energy policy • Community attitudes	• Skilled people • Transmission technology • Investment funds

This information has become a key input into the development of new transmission projects going forward. It is being used to consider and identify potential issues which may arise with the development of individual projects identified, such as the acquisition and location of new easements.

5 The Victorian electricity transmission network

The Victorian transmission network consists of various transmission lines and transformers that link power stations to the distribution system. The transmission network operates at voltages of 500 kV, 330 kV, 275 kV, and 220 kV. The 500 kV transmission network primarily transports bulk electricity from generators in the Latrobe Valley in Victoria's east, to the major load centre of Melbourne, and then onto the major smelter load and interconnection with South Australia in the west. Strongly meshed 220 kV transmission supplies the metropolitan area and major regional cities of Victoria.

The 330 kV transmission connects Victoria with the Snowy and New South Wales regions of the National Electricity Market (NEM), while transmission at 275 kV provides the interconnection with South Australia. Recent developments have connected two high voltage Direct Current (DC) interconnectors to the Victorian transmission network. One of the DC links forms the second connection with South Australia (Murraylink) while the other brings Tasmania into the NEM by connecting it with Victoria (Basslink).

The electricity transmitted through the transmission system is transformed to lower voltages at terminal stations, where it then supplies the distribution system. The shared transmission network in Victoria consists of electrical equipment at almost 50 terminal stations across the state with a total value of around $2 billion. The total circuit distance of major transmission lines is approximately 6,000 kilometres. Figure 5.1 provides a map of the existing Victorian transmission network.

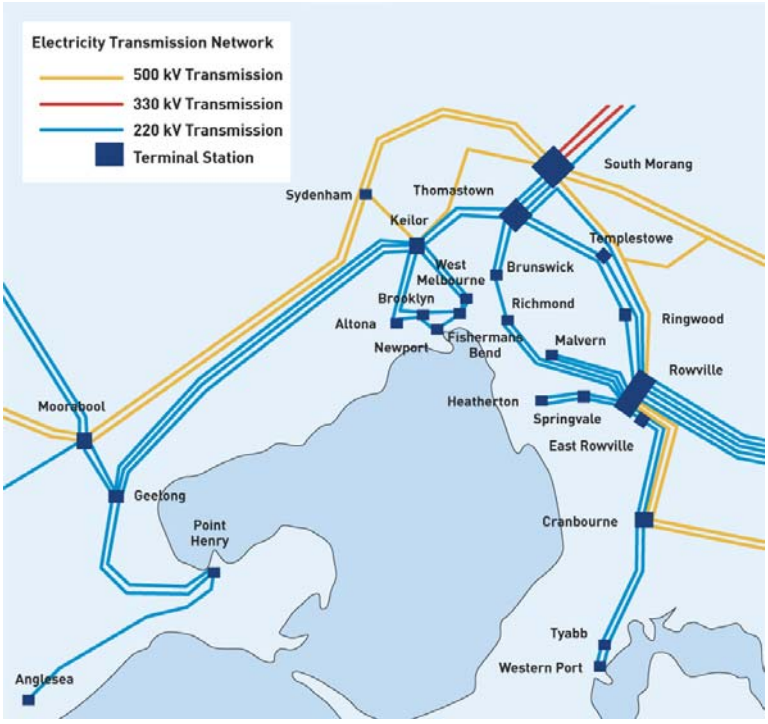
Figure 5.1 –Victorian electricity transmission network

The infrastructure in and around the greater metropolitan area encompassing Victoria's major load centres of Melbourne, Geelong and the Mornington Peninsula comprises two classes of assets in a classic demand centre configuration:

- an outer 500 kV high capacity ring around most of the area being supplied; and
- an inner 220 kV ring and radial connections, mainly supplied from the outer ring, to energy delivery points spread throughout the area.

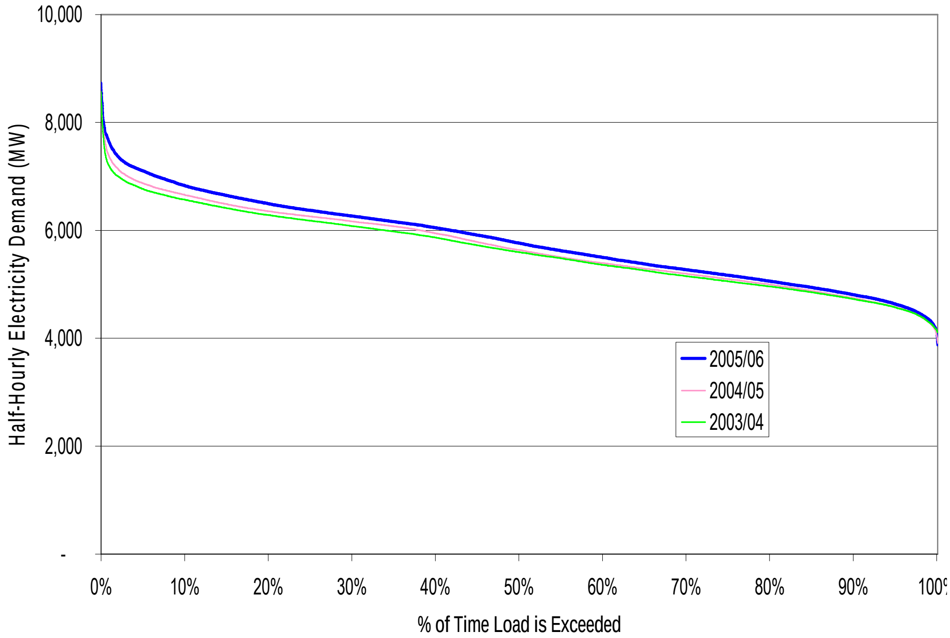
The arrangement of electricity transmission assets supplying the greater metropolitan areas of Melbourne and Geelong are shown in Figure 5.2.

Figure 5.2 –Melbourne Metropolitan electricity transmission network



Historical load curves, as shown in Figure 5.3 display the percentage of time that demand is above a certain MW level on an annual basis. It is evident that demand is greater than 85 per cent of maximum demands less than 1 per cent of times. The system load is becoming increasingly more summer and peaking in nature giving rise to an increasing difference between average and peak load.

Figure 5.3 –Load Duration Curve



6 Committed Augmentation Expenditure

This chapter provides a summary of committed augmentation expenditure. Committed augmentation expenditure relates to payments made by VENCorp to transmission asset owners for bulk transmission services provided under existing contracts won under the competitive tendering arrangements or where otherwise directed by VENCorp. The contracts relate to shared transmission services won or directed prior to regulation under the NER and those won or directed during the current regulatory period.

6.1 Committed augmentation expenditure prior to NER regulation

There are a number of contracts which VENCorp has entered into prior to NER regulation on 1 July 2002 which are being recovered as committed augmentation charges. These projects were reviewed by the AER at the time of VENCorp's first revenue cap application and are set out in Table 6.1

Table 6.1 –Committed augmentation expenditure prior to NER regulation

Augmentation	Provider	Contestable
SNOVIC, Capacitor Bank Network Service No.1,No.2, No.3	Transgrid	Yes
SNOVIC Non-contestable Services	SP AusNet	No
SNOVIC Interface Services	SP AusNet	No
Manual Load Shedding at ERTS, HTS & SVTS	SP AusNet	No
ATS, BLTS, KTS Autoreclose	SP AusNet	No
Contingency Load Shedding at ROTS, HTS & SVTS	SP AusNet	No
Uprating RTS - BTS Cable	SP AusNet	No
Series Capacitors	SP AusNet	Yes
Series Capacitors Interface Works	SP AusNet	No
Rowville 1,000 MVA 500/220 kV A1 Transformer	Rowville Transmission Facility	Yes
Protection Upgrade on TTS No 3 & 4 Buses	SP AusNet	No
500kV Protection Upgrade	SP AusNet	No
Reactive Support 2001/02-2003/04	SP AusNet	Yes
ROTS A1 220kV CB Replacement Project	SP AusNet	No

6.2 Committed augmentation expenditure during the current regulatory period

VENCorp's current revenue cap was set on the basis of the planned augmentations set out in Table 6.2 and approved by the AER in its decision of 11 December 2002.[9]

9 References to the AER are intended to read as references to the ACCC where appropriate.

Table 6.2 – AER approved planned augmentation projects for current regulatory period

Augmentation	$(millions) nominal excluding GST *^	Timing
4th 500 kV line project and associated 1000 MVA transformer at Cranbourne or Rowville	37	2003
4th Dederang 330/220 kV transformer and Mt Beauty 220 kV switchgear replacement	13	2004
Moorabool 1000 MVA 500/220 kV transformer spare phase	4	2004
Fault Level Mitigation	11	From 2004
Reactive Support	32	From 2003
Upgrade Rowville – Springvale – Heatherton 220kV lines	2	2004
Upgrade Ringwood 220kV supply	4	2003
Miscellaneous Works[10]	16	From 2003
Metropolitan 1000MVA 500/220kV transformer	32	2006
Rowville – Richmond 220kV lines upgrade	4	2007
Total	155	

*VENCorp's revenue cap decision of 11 December 2002 was set by the AER in real dollars based on scenario 1, using real cost data as at 1 July 2002. VENCorp has inflated the augmentation costs using an inflation rate of 2.04 per cent which was set by the AER for SP AusNet's revenue decision of the same date.
^ Where the date specifies works 'from' a particular year the project is assumed to be incurred in equal increments across all years until the end of the regulatory period.

In addition, on 3 May 2004 augmentations to facilitate the conversion of Murraylink from an unregulated interconnector to a regulated interconnector were approved by the AER under a revocation and substitution of VENCorp's revenue cap. The forecast capital cost was $15 million, taking the total allowed augmentation expenditure to $170 million.

Table 6.3 sets out all projects which were assessed against the regulatory test in the current regulatory period. VENCorp's new large network asset applications and EAPRs, which set out the regulatory test analysis for new small and minor transmission network assets, for the current regulatory period have been provided with this revenue proposal.

[10] This category represents provision for unidentified works that are generally less than $1million. For example, protection, control and termination equipment upgrades and other works required to maintain the reliability of the transmission+ network. As with other projects, works in this category will only proceed if justified in accordance with the Regulatory Test.

Table 6.3 –Committed augmentation expenditure during current regulatory period

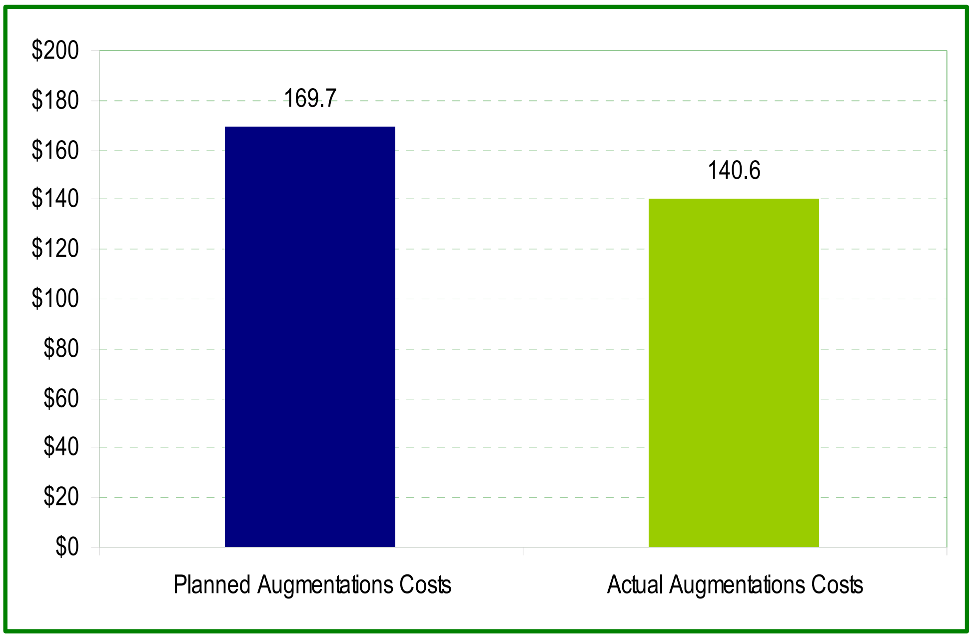
Augmentation Name	Reason for augmentation	Regulatory Test Cost $(millions) excluding GST*	Date of practical completion
Moorabool 1,000 MVA 500/220 kV A2 transformer	To address load growth in the western Melbourne metropolitan area.	17	Likely completion - March 2008
Rowville 1,000 MVA 500/220 kV A2 transformer and fault level mitigation	To address load growth in eastern Melbourne metropolitan area	37.2	Likely completion - September 2007
Latrobe Valley to Melbourne 4th 500 kV line upgrade project	To address load growth in eastern Melbourne metropolitan area	35.9	Dec-04
Murraylink Regulation Project	To support an interconnector linking Victoria and South Australia	15	Jan-06
Moorabool 500/220 kV spare single-phase transformer	To address load growth in the Geelong area.	4.5	Dec-05
Rowville to Springvale 220 kV line terminations upgrade	To address load growth in the Springvale and Heatherton areas	2	Sep-06
Rowville to Richmond No. 1 & 4 220 kV line termination plant upgrade	To address load growth in eastern Melbourne metropolitan area	1.25	Sep-06
Keilor fast load shedding control scheme	To address load growth in the western Melbourne metropolitan area.	0.4	Dec-05
Thomastown to Templestowe 220 kV line upgrade Thomastown to Ringwood 220 kV line upgrade	To address load growth in eastern Melbourne metropolitan area	3	May-06
Keilor to Geelong 220 kV lines wind monitoring scheme	To address load growth in the western Melbourne metropolitan, Geelong and south west state grid areas.	0.4	Sep-06
Moorabool A1 transformer connection upgrade			Sep-06
Shepparton to Fosterville to Bendigo 220 kV line wind monitoring scheme	To address load growth in the state grid area.	0.6	Sep-06
Moorabool to Ballarat 220 kV line wind monitoring scheme	To address load growth in the state grid area.	0.4	Sep-06
Yallourn to Hazelwood to Rowville 220 kV Wind Monitoring Scheme	To address the transfer of power from generation in the La Trobe Valley	0.6	Jan-07
Modification to Dederang Bus Splitting Scheme	To address load growth in the northern state grid area and Melbourne metropolitan area	0.1	Dec-05

When comparing Tables 6.2 and 6.3 it is clear that the installation of the fourth Dederang 330/220 kV transformer did not proceed, as it was not found to be required over the period. Further the requirement for reactive support works were displaced by a number of projects which occurred over the regulatory period such as the installation of the capacitor bank at Rowville, the works associated with the Murraylink interconnector, the completion of the La Trobe Valley to Melbourne project, the installation of the two transformers at Rowville and Moorabool and other works including connections between the transmission and distribution network.

However, during the period VENCorp justified the installation of a second transformer at Moorabool, based on a detailed regulatory test assessment, which had not been forecast at the time of the revenue reset.

The actual dollar amounts for these projects have been provided in Attachment 4. Due to the nature of the contracts entered into by VENCorp this information is confidential. Figure 6.1 provides a comparison of the forecast augmentation expenditure with the total actual augmentation expenditure. VENCorp's expenditure was around $20 million less than forecast at the time of the 11 December 2002 decision.

Figure 6.1 –Comparison of forecast augmentation expenditure with total augmentation expenditure



A year on year breakdown of this information has also been provided in Attachment 4.

6.3 Conversion of committed and funded augmentations to prescribed services

Under the terms of network agreements between VENCorp and SP AusNet non-contestable augmentations which were previously classified as *committed augmentation charges* are recovered under separate funded augmentation contracts can be rolled into SP AusNet's regulated asset base. While *prescribed service charges* will be recovered through TUoS charges those assets which were billed as funded augmentations will still be charged to the service applicants. They will not be recovered through TUoS charges.

SP AusNet has advised that of the projects identified above it proposes to roll those listed in Table 6.3 into its regulated asset base to be recovered through *prescribed services charges.*

Table 6.4 –SP AusNet projects to be rolled into its regulated asset base

Augmentation
SNOVIC Interconnector non-contestable works
ROTS A1 220kV Circuit Breaker non-contestable works
4th 500kV Transmission Line Upgrade Project non-contestable works
Murraylink Run-back Scheme
Transmission upgrade to Geelong Area - KTS Fast Load shedding scheme
Transmission upgrade to Geelong Area - MLTS Spare Phase Transformer
Brooklyn Series Reactors Project
ROTS-SVTS 220kV line terminations upgrades
MLTS-BATS Line Wind Monitoring

6.4 Committed Augmentation Charges

Table 6.4 sets out the committed augmentation charges for the forthcoming regulatory period based on the information in sections 6.2 and 6.3.

Table 6.5 – Committed Augmentation Charges

	$(millions) nominal excluding GST					
	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Committed Augmentation charges	22.9	23.6	24.3	25.0	25.7	26.5

7 Planned Augmentation Expenditure

This section sets out VENCorp's planned augmentation expenditure program for the forthcoming regulatory period. The augmentation requirements have been determined based on the Victorian electricity annual energy consumption, and summer and winter maximum demand forecasts over the regulatory control period. The forecasts presented are updates of those provided in VENCorp's 2006 EAPR. This chapter should therefore be read in conjunction with the 2006 EAPR.

7.1 Demand Forecasts

VENCorp engaged the National Institute of Economic and Industry Research (NIEIR) to prepare Victorian long-term electricity energy and demand forecasts for medium, high and low economic growth scenarios for its 2006 EAPR. NIEIR has developed an integrated multi-purpose model linking economic projections to energy forecasts. Details of the forecast methodologies, assumptions and other supporting load analysis can be found in the 2006 EAPR.

Table 7.1 presents the Victorian Gross State Product (GSP) growth, the annual energy, the 10% Probability of Exceedence (POE) summer maximum demand and the 10% POE winter maximum demand forecasts for the regulatory control period.

Table 7.1 – Summary of annual energy, 10% POE summer and winter maximum demand forecasts for the regulatory control period (Medium growth scenario)

Financial Years	Victorian GSP Growth (%)	Annual Energy (GWh)	10% POE Summer MD (MW)	10% POE Winter MD (MW)
2008/09	2.3	52,350	10,683	8,121
2009/10	1.4	51,673	10,819	8,154
2010/11	2.7	51,668	10,990	8,222
2011/12	3.0	51,807	11,163	8,306
2012/13	2.4	52,781	11,415	8,468
2013/14	2.8	53,383	11,627	8,584
2008/09-2013/14 Average Annual Growth rates	2.4%	0.4%	1.7%	1.1%

Source: VENCorp, 2006 Electricity Annual Planning Report p 10, 114

Victorian GSP is expected to grow by an average of 2.4 per cent over the regulatory period which is slower than the national average by around 0.5 per cent over the regulatory control period as the commodity boom continues to fuel the economic growth in the northern states. A sharp fall in the State GSP is projected for 2009/10 driven by a slow down in both business and government investments in Victoria.

Annual energy consumption is forecast to grow to 53,383 GWh by the end of the regulatory control period at an average rate of 0.4 per cent which is weaker than the average growth of 1.5 per cent over the current regulatory control period. This is due to a combination of the projected slower growth in the GSP and Commonwealth and State Government greenhouse gas initiatives, such as the Victorian Government's renewable energy strategy target of 10 per cent of Victorian electricity annual consumption will be met by renewable energy in 2010 and 5 star building standards for new homes.

The 10% POE summer maximum demand is projected to grow from 10,683 MW to 11,627 MW over the regulatory control period at an average rate of 1.7 per cent. This compares with the much stronger average growth of 3.3 per cent per annum over the previous regulatory period due to the moderating penetration of air conditioning, the potential impacts of the government's greenhouse gas initiatives noted previously, and the projected increase in non-scheduled generation. Winter maximum demand is expected to grow by 1.1 per cent over the same period, which is less than the summer maximum demand due to the dominance of gas heating in Victoria.

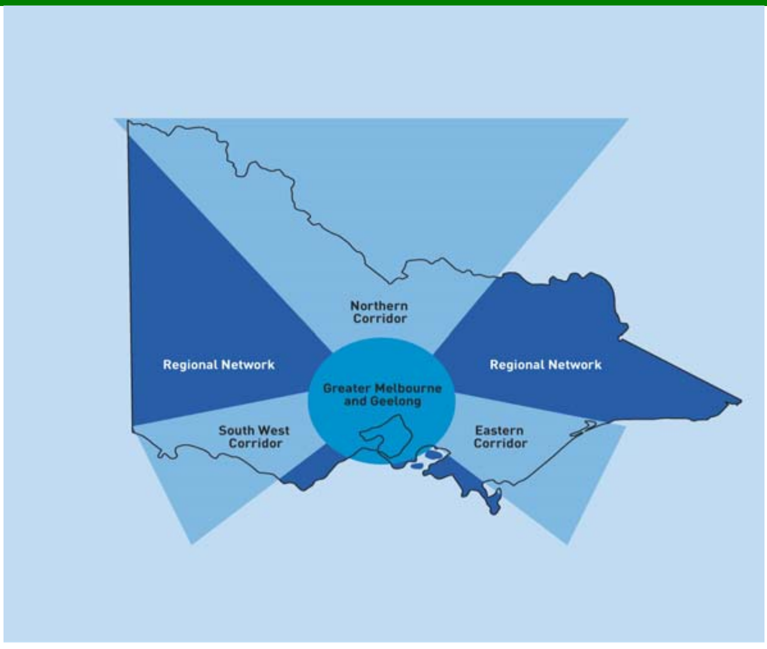
7.2 Augmentation Expenditure forecast for the period 1 July 2008 to 30 June 2014

Victoria's energy transmission infrastructure can be broadly described as a combination of the following elements:

- infrastructure in the greater metropolitan area of Melbourne and Geelong to deliver energy to distribution take-off points spread through the various cities and suburbs in this region;
- three major energy transmission corridors (Eastern, Northern and South West) to move bulk energy to the metropolitan demand centre or to other inter-state markets; and
- regional infrastructure to deliver energy to provincial cities and other demand centres in the regional areas of the state.

These corridors are depicted in Figure 7.1.

Figure 7.1 – Victoria's energy transmission corridors



VENCorp's planned augmentation expenditure forecasts are based on modifications to the detailed modelling conducted for the 2006 EAPR within these corridors. There are a number of factors that will tend to preserve this existing broad topology into the long-term future. These include:

- the location of major long-term fuel sources;
- the long service life of existing assets and relatively low future demand growth; and
- the continuing dominance of the greater metropolitan area as the primary demand centre.

While VENCorp plans network augmentations using a probabilistic approach, its has only conducted a preliminary probabilistic analysis for projects which fell within the 2006 EAPR's five year window, that is to 2011. For projects identified to 2013/14 constraints and possible solutions are identified based on a deterministic basis. A probabilistic analysis of the amount of energy at risk due to these network constraints has not been undertaken so the timing of any possible augmentation works is only indicative and would be confirmed by full economic assessment at an appropriate time in the future. However, some level of probabilistic analysis judgment is used to identify the indicative timing of each of the options identified.

It is most likely that future infrastructure development will utilise existing assets, especially sites and easements, in an evolutionary manner, rather than through unexpected major changes in this broad framework. VENCorp's augmentation plan has been developed on this basis.

For the purposes of this revenue proposal, the forecast augmentation program has been developed assuming a maximum demand of 11,627 MW in 2013/14. To meet this demand and to allow for up to 500 MW export to South Australia, approximately 1,500 MW of additional new generation will be required in Victoria by 2013/14.

Table 7.2 provides the supply-demand balance used to identify augmentation requirements over the regulatory control period, which sets out the level of existing and committed generation, import and export levels, Victorian demand and the reserve levels used to determine the requirement for additional new generation.

Table 7.2 – Supply and demand balance for 2013/14

Demand	Victorian maximum demand (10% POE)	11,627
	Export to South Australia	500
	Victorian Reserve level[11]	265
	Total demand plus reserve level	12,392
Supply	Total Supply	10,969
Amount of additional new generation needed		1,423 (~1,500)

As the location and size of generation will impact on the augmentations required on the transmission network, a range of supply scenarios, which load different parts of the transmission network, have

[11] Combined Victoria and South Australian reserve is 615 MW.

been examined. These scenarios, which correspond to the transmission corridors illustrated in Figure 7.1, are set out in Table 7.3.

Table 7.3 – Supply Scenarios to 2013/14

Scenario	Description	Increased Latrobe Valley Generation (MW)	Increased South Western Victoria Generation (MW)	Increased Import from Snowy/NSW (MW)	Metro/State Grid Generation/ DSM (MW)	Total Additional Supply (MW)
1	Predominantly Latrobe Valley generation (Eastern)	1,200	0	0	300	1,500
2	Predominantly South West generation (South West)	200	700	0	600	1,500
3	Predominantly Increase in import from Snowy/NSW (Northern)	600	0	600	300	1,500
4	Predominantly High metropolitan and State Grid generation (Metropolitan and State Grid)	300	0	0	1,200	1,500

At present, export from Victoria is limited at 1,100 MW to Snowy/NSW, 500 MW to Tasmania, and 680 MW to South Australia.[12] An additional two scenarios have also been included to assess the effect on the Victorian transmission network, for an increase in export level to Snowy/NSW and South Australia. These scenarios are set out in Table 7.4.

Table 7.4 – Export Supply Scenarios to 2013/14

Scenario	Description	Increased Latrobe Valley Generation (MW)
5a	Increase in export to Snowy/NSW	Increased export of 200 MW to Snowy/NSW during low to moderate demand periods
5b	Increase in export to South Australia	Increased export of 300 MW to South Australia during low to moderate demand periods

The scenarios selected are consistent with Vision 2030. They provide a representation of the many plausible scenarios for the development of the transmission network. Based on this analysis VENCorp has identified the need for three types of augmentations: predominantly *load driven augmentations; generation and import driven augmentations* and *export driven augmentations*.

12 The AEMC is currently reviewing changes to the regional boundaries which may result in a change to the representation of the export figures to NSW.

Predominantly load driven augmentations

Predominantly load driven augmentations are primarily driven by increasing load growth and are required irrespective of the location of new generation to meet the load growth. They are predominantly located in the metropolitan area.

Attachment 5 outlines the proposed forecast augmentation program for the forthcoming regulatory control period. Of the projects identified, three projects fall within the category of new large transmission network asset. These projects and the associated constraints are set out in Table 7.5.

Table 7.5 – Load Driven Augmentations – New Large Transmission Network Assets

Constraint	Likely new large network asset to address the constraint	Estimated timing	Estimated Cost ($ millions) real excluding GST
Loading of metropolitan transformer	1000MVA 500/220kV metropolitan transformer	2011/12	44
Security of supply to radially connected Springvale, Heatherton and Malvern terminal stations	220kV cable Malvern to Heatherton	2011/12	44
Wind generation located in state grid	Static Var Compensator in state grid area	2010/11	25
Total			113

The remaining load driven augmentations include a number of small and minor network augmentations including fault level mitigation works, line terminations upgrades, secondary equipment and dynamic system and supply of quality monitoring equipment and reactive support. These small and minor projects total $114 million, bringing the total capital cost for load driven augmentations to $227 million over the regulatory period.

This increase in augmentation requirements for the forthcoming regulatory period compared with the previous regulatory period is driven by the increase in the length of the regulatory period from five years to six years and the increasing cost of network augmentations driven by the global increase in the cost of network assets. As a result of the increasing project costs VENCorp has based its revenue proposal on the upper end of the reasonable range of costs estimates. VENCorp obtains these cost estimates from SP AusNet as part of its preparation for the EAPR. Where possible, these estimates are subject to due diligence with the actual cost of the project compared with recently completed similar projects.

Predominantly generation driven augmentations

Generation driven augmentations are dependent on the timing and location of new generation to meet the load growth and include import driven augmentations. These augmentations are still required to meet load growth, and will be assessed against the regulatory test on this basis. The flow paths from generation to load will determine when and where these augmentations are located. Due to the uncertainty in the timing of when these augmentations will be required they have not been dated, however, they are unlikely to be required until 2010/11 at the earliest. Therefore, for the purposes of this revenue cap proposal the expected value of the cost of these augmentations have been spread evenly across 2011/12 to 2013/14.

The generation driven works are based on the expected value of developments arising from the four scenarios, noted in Table 7.3, to meet demand growth. They have been named according to where the main component of the generation will be located. These are:

- Predominantly Latrobe Valley Generation (Scenario 1);
- Predominantly South West Generation (Scenario 2);
- Predominantly Increase in import from Snowy/NSW (Scenario 3); and
- Predominantly High Metropolitan and State Grid Generation (Scenario 4).

Table 7.6 sets out the new large transmission network assets for generation driven augmentations for these scenarios.

Table 7.6 –Predominantly Generation Driven Augmentations– New Large Transmission Network Assets

Constraint	Likely new large network asset to address the constraint	Scenario required	Estimated Cost ($ millions) real excluding GST
Inadequate thermal capacity of Loy Yang to Hazelwood 500 kV lines	4th 500kV line Loy Yang to Hazelwood	1,3	38
Outage of a Hazelwood 500/220 kV transformer overload the parallel transformers	Another 500/220kV transformer at Hazelwood	1,2,4	28
South Morang to Dederang 330 kV line and series capacitors overload for outage of parallel circuit	3rd 700MVA 330/220kV transformer at South Morang	3	25
Wind generation located in state grid.	Additional Static Var Compensators in the state grid area	4	25
Network reactive support in the metropolitan area	Additional reactive support in metropolitan area	1	25
Fault level issues	Additional fault limiting devices in the metropolitan area	4	25
Thermal loading of lines in the Malvern area	220kV line uprate to 82deg Rowville to Malvern	1,2,3,4	22
No suitable connection point for possible large generators around Mortlake	New 500kV TS near Mortlake	2	15.
Murray to Dederang 330 kV line overload for outage of parallel circuit	Series compensation plus shunt capacitor banks at Wodonga/Dederang	3	15.
Dederang 330/220 kV transformers overload for an outage of a parallel transformer	4th 330/220kV transformer at Dederang	1,2,3,4	14
Fault level issues	Fault limiting devices in state grid area	4	13
Total			245

There are a number of other minor and small transmission network projects which may be required in each of the scenarios identified such as fault level mitigation works, line terminations upgrades and reactive support.

Assuming an equal probability for all scenarios identified, the expected value of the predominantly generation driven works program is $125 million.

This is in contrast to the current regulatory period where there have not been any augmentations driven by the location of new generation in Victoria.

Export driven augmentations

A number of other augmentations have been identified which may be required to increase Victoria's export capability during periods of light load. However, due to the uncertainty of the need to undertake this work no allowance has been included in the revenue proposal. Should the need for these augmentations arise which will, or will be likely to, result in VENCorp exceeding its MAAR VENCorp would seek to re-open its revenue cap under the provisions of clause 9.8.4C(g2) of the NER[13]. These augmentations are set out in Table 7.7.

Table 7.7 – Export Driven Augmentations – New Large Transmission Network Assets (Scenario 5)

Constraint	Likely new large network asset to address the constraint	Scenario required	Estimated Cost ($ millions) real excluding GST
Outage of a Heywood 500/275 kV transformer overloads the parallel transformer	3rd 275kV line Heywood to South East	5b	69
South Morang 500/330 kV transformer overload with increased export to Snowy/NSW	2nd 1000MVA 500/330kV transformer at South Morang	5a	44
Reactive support and voltage control in the Heywood area	Static Var Compensator at Heywood	5b	28
Outage of a Heywood 500/275 kV transformer overloads the parallel transformer	3rd 500/275kV transformer & bus tie at Heywood	5b	25

7.3 Funded augmentations

It is worth noting that it is possible that some of the load driven augmentations and generation driven augmentations may become displaced by funded augmentations which result from new connections in accordance with the principles set out in VENCorp's Connection Augmentation Guidelines. Any funded augmentations may reduce the need for VENCorp to augment the network going forward. However, it is not possible at this stage to identify when and where the funded augmentations will be required due to uncertainty of the size, timing and location of new generation and load investments.

13 Clause 9.8.4C(g2) of the NER states that "If VENCorp's statutory electricity transmission-related costs for a financial year have exceeded, or VENCorp anticipates (as a result of receiving a notice from a Regulated owner under clause 9.8.4C(g1) or otherwise) that they will exceed, the amount of the statutory electricity transmission-related costs for that financial year assumed by the AER in making the determination of VENCorp's maximum allowable aggregate revenue, VENCorp may apply to the AER for an adjustment to the maximum allowable aggregate revenue for each affected financial year in the relevant regulatory period of an amount, set out in the application, equal to the amount required to ensure that the maximum allowable aggregate revenue complies with the principles in clause 9.8.4C(a)."

7.4 Planned augmentation charges

Taken together the value of the forecast augmentation expenditure program is $354 million over the relevant regulatory period. The cost of the predominantly generation driven works are aggregated and then smeared equally over the period 2010/11 to 2013/14 inclusive.

Table 7.8 sets out the profile of when the expenditure is forecast to be required across the regulatory period.

Table 7.8 –Planned Augmentation expenditure – year on year

	$(millions) real excluding GST					
	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Planned Augmentation expenditure	2.0	15.6	51.7	79.3	138.0	67.3

For the purposes of this revenue proposal the planned augmentation charges have been calculated assuming:

- a nominal vanilla Weighted Average Cost of Capital (WACC) of 8.5 per cent; which is in line with the AER's draft decision for Powerlink of 8.76 per cent [14] and
- straight line current cost depreciation charge over 30 years, which is the average of VENCorp's current committed projects and is also the likely timeframe over which a number of the contracts will be entered into for the identified projects..

However, it should be noted that when VENCorp enters into agreements with parties for the provision of services it typically receives a schedule of annual charges for the life of the project. The agreements are not based on a VENCorp determined WACC. The financing charges will be determined at the time that VENCorp enters into contracts with the specific parties for augmentations and the length of the contracts will be based on the nature of the projects that are required.

Therefore, in so far as the modified transmission price regulation regime is concerned, this information is provided simply to allocate VENCorp's maximum allowable aggregate revenue for each year of the forthcoming regulatory period (ie. its forecast statutory electricity transmission-related costs for each such year) in accordance with the requirements of Part J of Chapter 6A of the NER, and to convert the resultant planned augmentation expenditure to the prices charged by VENCorp for the network services that it provides (NER, cl.9.8.4F(a), (c)(1), (c)(2)(i)(C); see also cl.9.8.4B(a)(2)(iv)).

Based on the above the planned augmentation charges are set out in Table 7.9.

[14] Australian Energy Regulator, Draft Decision Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12, p 113.

Table 7.9 –Planned Augmentation Charges

	$(millions) nominal excluding GST					
	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Planned Augmentation charges	0.2	1.7	6.8	15.8	31.8	43.0

While the planned augmentation charges are based on what VENCorp considers to be reasonable estimates for the purposes of this revenue proposal, the actual charges will be based on the outcomes of the individual regulatory test assessments, competitive tendering provisions or directions of VENCorp through the regulatory period.

It should also be emphasised that VENCorp does not recover the charges set out in this revenue proposal. Under the framework in which VENCorp operates it is only able to recover those charges that are required to meet its statutory electricity related functions.

Therefore, to the extent that a more efficient solution can be identified closer to the time at which an actual augmentation might be required to address an emerging constraint, or the market provides a solution which defers or eliminates the need for an augmentations, consumers will not be charged an amount based on this revenue proposal. They will only be charged the amount that VENCorp requires to meet the actual costs of providing these services.

8 Operating and Planning Expenditure

This section sets out VENCorp's proposed operating and planning expenditure for the forthcoming regulatory period. VENCorp's operating and planning expenditure constitutes less than 2 per cent of transmission network charges in Victoria which equates to approximately 0.1 per cent of total delivered electricity costs.

8.1 Overview of cost forecasts and key assumptions

The budgeted operating and planning expenditure includes all direct and indirect costs associated with VENCorp's statutory electricity industry functions. The categories of operating and planning expenditure are explained in further detail in Attachment 6.

Table 8.1 sets out VENCorp's forecast operating expenditure for the forthcoming regulatory period.

Table 8.1 – Forecast Operating and Planning Expenditure

	$(millions) nominal excluding GST					
	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Labour	2.94	3.07	3.18	3.36	3.48	3.62
Contracted Services	0.22	0.24	0.24	0.25	0.25	0.26
Computing and communications	0.63	0.68	0.69	0.71	0.73	0.75
Consultancies and contractors	1.12	1.17	1.19	1.25	1.28	1.32
Vehicles & Travel	0.06	0.06	0.06	0.06	0.07	0.07
Occupancy	0.18	0.18	0.19	0.20	0.20	0.21
Administrative Costs	0.11	0.12	0.12	0.12	0.13	0.13
Depreciation & Amortisation	0.12	0.13	0.13	0.13	0.14	0.13
Service Department Allocations	1.30	1.34	1.36	1.40	1.44	1.48
Total Operating and Planning Expenditure	6.69	6.98	7.17	7.47	7.71	7.98

VENCorp's operating and planning expenditure is expected to continue along its current trend with $6.7 million forecast to required in 2008/09. The majority of these costs are made up of labour (approximately 45 per cent), consultancies and contractors (approximately 16 per cent) and service department allocations (approximately 20 per cent) which together represents around 80 per cent of VENCorp's operating and planning budget. They have been derived based on best estimates of VENCorp's requirements to meet its statutory electricity transmission-related obligations using 2006/07 as the base year given that it was the most recent and most relevant data at the time that theses forecasts were prepared.

The majority of VENCorp's costs will remain relatively stable and are required to be incurred to enable VENCorp to carry out its statutory electricity related functions. The two major variables are:

- labour costs - due to the annual adjustment that is required each year to revalue VENCorp's defined benefit superannuation obligation, and
- consultancy costs which can vary from year to year depending on what 'one-off' projects are required to be undertaken in any one year.

It is evident that the main driver for the modest increase over the regulatory period is associated with labour costs. VENCorp is forecasting the cost of labour to increase by an average of 4.5 per cent per annum over the regulatory period. These costs are in line with VENCorp's Enterprise Bargaining Agreement and estimated performance based increases. VENCorp also notes its forecast labour cost growth is consistent with the AER's own views based on the Access Economics report commissioned by the AER for the Powerlink revenue reset.[15]

All other expenditure has been budgeted in line with known contracted amounts or best estimates and are assumed to increase by 3 per cent on average. While this is at the higher end of the Reserve Bank of Australia's forecast band it is still nevertheless within this band.[16]

8.2 Comparison of costs in current regulatory period

Table 8.2 sets out a comparison of VENCorp's actual with allowed operating expenditure over the current regulatory period.

Table 8.2 – Comparison of Actual with Allowed Operating and Planning Expenditure

	$(millions) nominal excluding GST									
	2003/04		2004/05		2005/06		2006/07		2007/08	
	A	F	A	F	A	F	B	F	B	F
Operating and Planning Expenditure	4.7	5.5	4.8	5.7	3.4	6.0	6.3	6.1	6.3	6.2

A – Actual
F – Allowed under AER's revenue cap
B – Budgeted

VENCorp's actual operating and planning expenditure has generally been lower than that allowed in the regulatory control period. The main factor contributing to this has been the lower expenditure on labour costs arising from a defined benefit superannuation 'holiday' and a delay in filling some internal vacancies.

In 2005/06 the actual expenditure was significantly lower, primarily as a result of a positive adjustment to VENCorp's defined benefit superannuation obligation. VENCorp was required to bring this to account under the International Financial Reporting Standards (IFRS). The defined benefit superannuation adjustment required under IFRS in 2005/06 was $1.2 million and the defined benefit superannuation holiday in 2005/06 was $0.1 million.

15 Access Economics, Wage growth forecasts in the utilities sector, 17 November 2006.

16 VENCorp notes that page 3 of the Access Economics' report states the following on inflation:

> The inflation rate tends to move with the economic cycle (lagging by around 18 months). Broadly speaking, inflation rates should remain within the Reserve Bank's stated 2-3% price band. While the headline rate should average slightly less than rates we have seen recently, the underlying rate may be slightly higher than over the past few years. The higher underlying rate is expected as the benefits of increasing low cost imports from China will have a lesser effect in coming years as the Australian dollar eases, and also as (relatively fast growing) health and medical costs take up an increasing share of the economy as the population ages.

With the assumption that the defined benefit ‘holiday’ will not continue and that all vacant positions will be filled, along with increasing connection assessments and network planning necessitating additional consulting services, VENCorp is budgeting to exceed the amount allowed under its revenue cap for the remainder of the regulatory control period by $0.1 million.

Attachment 7 provides a detailed breakdown and comparison of actual and forecast expenditure over the regulatory control period.

8.3 Cost control and efficiency improvement initiatives

Given VENCorp’s not-for-profit status its management and internal control arrangements reflect a keen awareness that all electricity statutory costs incurred must ultimately be recovered through TUoS charges. VENCorp is constantly seeking ways to improve the efficiency and cost-effectiveness of the organisation.

Development of career plans for employees and staff-management relations are priorities for the organisation, while scrutiny of costs receives maximum focus. Accordingly VENCorp maintains a system of very limited expenditure delegation; and regardless of whether or not an approved budget provision exists for an item of expenditure, all expenditure must be justified prior to proceeding.

8.4 Allocation of costs between VENCorp functions

VENCorp’s statutory functions include responsibilities in both gas and electricity. VENCorp’s electricity and wholesale gas functions are regulated by the AER while its FRC activities are regulated by the Essential Services Commission.

Where practicable, costs will be allocated directly to the business function (i.e. electricity, wholesale, contestability) that the cost relates to. Costs that are allocated to the Corporate Department are fully apportioned to the functions of the business based on the following allocation methods:

- Full Time Equivalents (FTEs) per function as a percentage of total organisational FTEs. Corporate costs associated with Computing, Depreciation, Insurance and Occupancy is allocated on this basis. The rationale for this treatment is that these costs do not fluctuate in line with the number of hours worked; and
- The number of hours worked on a function as a percentage of total organisational hours. Following the completion of the allocations based on FTEs, the remaining corporate costs are allocated based on the number of hours worked on a function as a percentage of total hours worked in the organisation. The rationale for this treatment is that the number of hours worked by a particular function of the business will require a proportionate amount of service delivery from the Corporate department. Therefore, the more hours of work on a function, the more time and resources the Corporate Department assigns for this function and vice versa.

8.5 Most recent forecast of VENCorp’s Statutory Electricity Related Costs

Clause 9.8.4C(b) of the NER requires VENCorp to provide a statement reconciling its most recent forecast of revenue that will be recovered by way of shared transmission network usage charges and the statutory electricity transmission related costs, for the relevant regulatory period immediately preceding the relevant regulatory period to which the application relates.

VENCorp has included this information in Attachment 8.

9 Total Revenue Requirement

As noted previously, VENCorp's statutory electricity related transmission costs are comprised of the following:

- VENCorp's operating and planning costs;
- payments made by VENCorp to providers of new augmentations that will be required over the relevant regulatory period to maintain adequate levels of transmission system reliability and performance (*planned augmentation charges*);
- payments made by VENCorp to SP AusNet and other TNSPs for bulk transmission services provided under existing contracts won under the competitive tendering arrangements or where directed by VENCorp (*committed augmentation charges*); and
- payments made by VENCorp to SP AusNet and Murraylink for the provision of Prescribed Transmission Services, which are subject to separate regulation by the AER (*prescribed service charges*).

VENCorp's committed augmentation charges, planned augmentation charges and operating expenditure have been discussed in sections 6, 7 and 8 respectively. VENCorp's Prescribed Service Charges, including an allowance for the Availability Incentive Scheme (AIS) as set out in sections 9.1 and 9.2.

9.1 Availability Incentive Scheme

The AIS provides economic incentives for transmission network service providers to minimise outages that occur on Victorian transmission network largely by performing maintenance at a time when system demand is low.

In 2001, Trowbridge Consulting was engaged by SP AusNet to undertake an independent review of AIS prior to its negotiations with VENCorp to amend the scheme and provide an independent view on the expected total annual rebates to apply under the new scheme. Based on the findings in that report the expected total annual rebates were valued at $6 million. Further details of the AIS can be found in Attachment 9.

VENCorp has included an allowance of $6 million in each year of the regulatory period, which represents the cap of the AIS, However, it notes that the actual amount will depend on SP AusNet's performance over the regulatory period.

9.2 Prescribed Service Charges

The prescribed services charges set out payments made by VENCorp to SP AusNet and Murraylink for provision of prescribed services provided by these TNSPs. Prescribed charges relating to the Murraylink interconnector are based on the AER's revenue cap of 1 October 2003 and the agreement between VENCorp and ElectraNet on the allocation of prescribed service charges between Victoria and South Australia.

SP AusNet's estimated prescribed services charge have been based on information supplied to VENCorp by SP AusNet and based on its revenue proposal to the AER of 28 February 2007. The information supplied by SP AusNet assumes that VENCorp will recover 85 per cent of non Easement Tax revenue and 100 per cent of the easement tax. VENCorp has accepted this information from SP AusNet without amendment.

The prescribed services charges also include an allowance for the AIS as outlined in section 9.1.

The prescribed service charges required to be recovered by VENCorp are set out in Table 9.4.

Table 9.4 – Prescribed Services Charges

	$(millions) nominal excluding GST					
	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Prescribed Service charges	376	399.5	424.6	451.2	479.5	509.7

9.3 Total Revenue Requirement

Based on all of above components VENCorp's estimated total revenue requirement for the period ending 30 June 2014 is set out in Table 9.5.

Table 9.5 – Total Revenue Requirement

	$(millions) nominal excluding GST					
	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Operational Expenditure	6.7	7.0	7.2	7.5	7.7	8.0
Planned Augmentation charges	0.2	1.7	6.8	15.8	31.8	43.0
Committed Augmentation charges	22.9	23.6	24.3	25.0	25.7	26.5
Total forecast expenditure for VENCorp	29.8	32.2	38.3	48.3	65.3	77.5
Prescribed Services charges	376	399.5	424.6	451.2	479.5	509.7
Total Revenue Requirement*	404.7	430.8	461.8	498.5	543.8	586.2
*Energy (GWh)***	52,350	51,673	51,668	51,807	52,781	53,383
Victorian TUoS charges ($/MWh)	7.7	8.3	8.9	9.6	10.3	11.0

* - Total Revenue Requirement has been reduced by $1 million per annum to account for interest income earned by VENCorp

**- The energy value is on a generator sent out basis.

Attachment 1 Summary of relevant legal, regulatory and contractual instruments applicable to VENCorp

Electricity Industry Act

Section 79 of the Electricity Industry Act 2000 confers on VENCorp powers and responsibility for planning and directing the augmentation of the electricity transmission system.

VENCorp's Electricity Transmission Licence

Clause 4 of VENCorp's electricity transmission licence states that "VENCorp is responsible for planning and directing the augmentation of the shared network"[17].

Clause 5 of the licence requires VENCorp to offer shared network services to any existing or prospective user, on fair and reasonable terms. Under Clause 5.6, VENCorp must not refuse to make an offer to provide shared network services. These provisions of the licence effectively establish an 'open access' regime for the shared network, a monopoly facility. In providing such access, it may be necessary for VENCorp to augment the capability of the shared transmission network from time to time. Thus, the obligation under law to provide the monopoly transmission service on an open access basis also gives rise to an obligation to augment the network[18].

National Electricity Rules

In addition to being bound under the Victorian regulatory regime, VENCorp is also required to comply with the NER, in its capacity as a TNSP for the shared transmission network in Victoria.

Under Clause 5 of the NER VENCorp must offer to provide use of system services on fair and reasonable terms to any Code participant or intending Code participant (Clause 5.3.6 (c)). VENCorp must also arrange for and participate in planning and development of its network (Clause 5.2.3(d)(4)).

Victorian System Code

The latest version of the Victorian Electricity System Code[19] was issued in October 2000 by the Office of the Regulator General. This revised System Code removes participant operational obligations, and planning and performance issues that are adequately covered by the NER, and will continue to cover relevant Participant interface matters in Victoria, where such matters are not adequately covered by the NER, including coverage of:

- the process and time frame for Generating Companies to develop and conduct testing in relation to generator technical requirements in the National Electricity Code, and the process for dealing with non-compliance, and

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[17] The term "shared network" is defined in the licence as excluding generator and load connection facilities, because planning and augmentation of those facilities is the responsibility of the generators and distribution businesses, respectively.

[18] VENCorp's electricity transmission licence was last varied in 2005, and is available at the Essential Services Commission website at http://www.esc.vic.gov.au

[19] A copy of the System Code is available at the Essential Services Commission website at http://www.esc.vic.gov.au

- the staged process of dealing with any non-compliance by Distribution Companies with quality of supply requirements in the National Electricity Rules.

Use of System Agreements with Participants

VENCorp has a use of system agreement with each of the parties connected to the Victorian shared transmission network including Generating Companies and Distribution Businesses. These agreements require VENCorp to “use its reasonable endeavours to provide shared network capacity sufficient to meet the expected (forecast) demand at the Points of Supply”. Under these agreements, VENCorp therefore has a contractual obligation to augment the shared network to continue to meet expected load growth, subject to the regulatory test promulgated by the AER.

Attachment 2 Victorian Derogation

9.8.4B Transmission service revenues

(a) Despite anything to the contrary in Chapter 6A or in this Chapter 9, the applicable *transmission* revenue regulatory regime for the regulation of *transmission service* revenues in respect of the *Victorian Transmission Network* or a part of the *Victorian Transmission Network* is:

1. in relation to any transmission services provided by a Regulated owner, the transmission revenue regulatory regime set out in Chapter 6A and, for that purpose, every reference in Chapter 6A to a Transmission Network Service Provider is to be read as a reference to a Regulated owner; and

2. in relation to any transmission services provided by VENCorp, the transmission revenue regulatory regime set out in Chapter 6A as modified by clauses 9.8.4B to 9.8.4E, and for that purpose every reference in Chapter 6A to:

   (i) a *Transmission Network Service Provider* is to be read as a reference to *VENCorp*;

   (ii) the maximum allowed revenue for a Transmission Network Service Provider for a regulatory year of a regulatory control period is to be read as a reference to the maximum allowable aggregate revenue;

   (iii) a regulatory control period is to be read as a reference to a relevant regulatory period; and

   (iv) prescribed transmission services is to be read as a reference to services in respect of which VENCorp may determine shared transmission network use charges.

(b) In clause 9.8.4B(a)(1), transmission services includes shared network services.

9.8.4C Transmission revenue regulatory regime for transmission services provided by VENCorp

(a) The transmission revenue regulatory regime that applies to VENCorp must comply with the following principles:

1. the amount of VENCorp's maximum allowable aggregate revenue for a relevant regulatory period must not exceed VENCorp's statutory electricity transmission-related costs; and

2. VENCorp's maximum allowable aggregate revenue must be determined on a full cost recovery but no operating surplus basis.

(a1) For the avoidance of doubt, transmission services offered by VENCorp are not taken to be offered on a contestable basis by reason only of VENCorp having procured those services through a competitive tender or similar process.

(a2) The procedure set out paragraphs (b)-(g4) applies in relation to transmission services provided by VENCorp and Part E of Chapter 6A is modified in so far as it applies to the regulation of revenues.

(b) Not less than 7 months before the commencement of a relevant regulatory period, VENCorp must, for the purpose of enabling the AER to determine VENCorp's maximum allowable aggregate revenue for a relevant regulatory period, submit its revenue application for that relevant regulatory period to the AER that sets out:

(1) its proposed maximum allowable aggregate revenue for each financial year in that relevant regulatory period;

(2) its forecast statutory electricity transmission-related costs for each financial year in that relevant regulatory period; and

(3) [Deleted]

(4) a statement reconciling its most recent forecast of:

(i) the revenue that will be recovered by way of shared transmission network use charges; and

(ii) the statutory electricity transmission-related costs, for the relevant regulatory period immediately preceding the relevant regulatory period to which the application relates.

(c) The application must be:

(1) consistent with the principles set out in clause 9.8.4C(a); and

(2) in a form that meets the Information requirements guidelines but only to the extent to which those guidelines are relevant and applicable to VENCorp.

(d) Subject to clause 9.8.4C(e), (f), (g), (g3) and (g4), the AER must determine VENCorp's maximum allowable aggregate revenue for a relevant regulatory period.

(e) A determination under clause 9.8.4C(d):

(1) must apply the principles set out in clause 9.8.4C(a);

(2) must comply with the requirements set out in clause 6A.14.2, modified as necessary to apply to the revenue regulatory regime under this clause 9.8.4C;

(3) must take into account:

(i) VENCorp's functions under the EI Act, the application of the Rules to VENCorp and the conditions imposed on VENCorp under its transmission licence; and

(ii) [Deleted]

(iii) the difference (if any) between the forecasts referred to in clause 9.8.4C(b)(4); and

(iv) must set out the maximum allowable aggregate revenue for each financial year in that relevant regulatory period.

(f) If, after considering the application, the *AER* finds that there is a difference of the kind referred to in clause 9.8.4C(e)(3)(iii), the *AER* must apply that difference in any determination it makes under clause 9.8.4C(d).

(g) If the AER does not make a determination under clause 9.8.4C(d) before the commencement of the relevant regulatory period in respect of which the application was made, the AER is to be taken to have made a determination as to VENCorp's maximum allowable aggregate revenue in respect of each financial year in that relevant regulatory period on the same terms as the application.

(g1) If, at any time during a relevant regulatory period, a Regulated owner proposes to send a notice to the AER which could have the effect (directly or indirectly) of varying a charge, or introducing a new charge, payable by VENCorp to the Regulated owner during that relevant regulatory period for shared network services, the Regulated owner must first provide a copy of that notice to VENCorp.

(g2) If VENCorp's statutory electricity transmission-related costs for a financial year have exceeded, or VENCorp anticipates (as a result of receiving a notice from a Regulated owner under clause 9.8.4C(g1) or otherwise) that they will exceed, the amount of the statutory electricity transmission-related costs for that financial year assumed by the AER in making the determination of VENCorp's maximum allowable aggregate revenue, VENCorp may apply to the AER for an adjustment to the maximum allowable aggregate revenue for each affected financial year in the relevant regulatory period of an amount, set out in the application, equal to the amount required to ensure that the maximum allowable aggregate revenue complies with the principles in clause 9.8.4C(a).

(g3) Following an application by VENCorp under clause 9.8.4C(g2), the AER must determine the amount, if any, by which VENCorp's maximum allowable aggregate revenue for each affected financial year in the relevant regulatory period is to be adjusted so that it complies with the principles in clause 9.8.4C(a).

(g4) If the AER does not make a determination under clause 9.8.4C(g3) within 30 business days after the application by VENCorp under clause 9.8.4C(g2), the AER is to be taken to have made a determination that VENCorp's maximum allowable aggregate revenue for each affected financial year in the relevant regulatory period is to be adjusted by the amount set out in VENCorp's application.

(h) [Deleted]

9.8.4D Information disclosure by VENCorp

VENCorp must comply with Part F of Chapter 6A, but only to the extent to which it is relevant and applicable to *VENCorp.*

9.8.4G Transitional provisions

Despite anything to the contrary in clauses 9.8.4A to 9.8.4D, any determination of the *ACCC* setting *VENCorp's revenue cap* that is in force immediately before 1 January 2003 is deemed to be a determination of the *AER* under clause 9.8.4C(d), and for that purpose, clauses 9.8.4A to 9.8.4D and the provisions of Part B of Chapter 6 as modified by clauses 9.8.4A to 9.8.4D, apply accordingly.

Statutory electricity transmission-related costs

In relation to *VENCorp*, the sum of the following costs for a *relevant regulatory period*:

(1) *VENCorp's* aggregate actual costs in operating and planning the *Victorian Transmission Network*;

(2) all *network* charges payable by *VENCorp* to *SPI PowerNet* or any other owner of the *Victorian Transmission Network* or a part of the *Victorian Transmission Network*, including charges relating to *augmentations*;

(3) all other charges payable by *VENCorp* to providers of *network* support services and other services which *VENCorp* uses to provide *network services* that are *transmission services*; and

(4) any other costs that directly arise out of *VENCorp's* functions under the *EI Act* relating to the transmission of electricity, the application of the *Rules* to *VENCorp* or the conditions imposed on *VENCorp* under its *transmission licence* relating to the transmission of electricity, for which there is no alternative method (legislative or contractual) for the recovery of those costs.

Attachment 3 Negotiating Framework

At the same time as submitting a Revenue Proposal, VENCorp must also submit to the AER a proposed negotiating framework. The proposed negotiating framework must comply with the requirements of, and must contain or be accompanied by such information as is required by, the submission guidelines.

Section 5 of the AER's proposed submission guidelines requires the proposed negotiating framework to:

- specify that the TNSP must provide an applicant for a negotiated transmission service with a description of the nature of the negotiated transmission service, including details of what the TNSP would provide as part of that service;
- specify other matters and information which reflect the requirements in clause 6A.9.5 (most of these correspond with the requirements set out in clause 6.5.9 under the old regime); and
- not be inconsistent with clauses 5.3 (process and procedures for new or modified connections), 5.4A (access arrangements), old clause 6.4.7 (negotiated entry and exit service prices to be included in a connection agreement) and old Part C of Chapter 6 (pricing rules).

Clause 6A.9.5(c) provides that the negotiating framework for a TNSP must specify:

- a requirement for the provider and a Service Applicant to negotiate in good faith the terms and conditions of access for provision of the negotiated transmission service;
- a requirement for the provider to provide all such commercial information as a Service Applicant may reasonably require to enable that applicant to engage in effective negotiation with the provider for the provision of the negotiated transmission service, including the cost information described in subparagraph (3)
- a requirement for the provider:
  - o to identify and inform a *Service Applicant* of the reasonable costs and/or the increase or decrease in costs (as appropriate) of providing the *negotiated transmission service*; and
  - o to demonstrate to a *Service Applicant* that the charges for providing the *negotiated transmission service* reflect those costs and/or the cost increment or decrement (as appropriate);
- a requirement for a Service Applicant to provide all such commercial information as the provider may reasonably require to enable the provider to engage in effective negotiation with that applicant for the provision of the negotiated transmission service
- a reasonable period of time for commencing, progressing and finalising negotiations with a Service Applicant for the provision of the negotiated transmission service, and a requirement that each party to the negotiation must use its reasonable endeavours to adhere to those time periods during the negotiation;
- a process for dispute resolution which provides that all disputes as to the terms and conditions of access for provision of negotiated transmission services are to be dealt with in accordance with Part K of this Chapter 6A;
- the arrangements for payment by a Service Applicant of the provider's reasonable direct expenses incurred in processing the application to provide the negotiated transmission service;
- a requirement that the Transmission Network Provider determine the potential impact on other Transmission Network Users of the provision of the negotiated transmission service; and
- a requirement that the Transmission Network Service Provider must notify and consult with any affected Transmission Network Users and ensure that the provision of the negotiated transmission services does not result in non-compliance with obligations in relation to other Transmission Network Users under the Rules.

The following sets out VENCorp’s electricity negotiating framework.

Negotiating Framework For Electricity Negotiable Services

This document sets out VENCorp's negotiating framework for the purposes of clause 6A.9 of the National Electricity Rules, and forms part of VENCorp's *transmission determination* for the period 1 July 2008 to 30 June 2014. The terms used in this document are defined in the National Electricity Rules.

1. Negotiation in good faith and reasonable endeavours to adhere to time periods

VENCorp and a *Service Applicant* shall negotiate in good faith *the terms and conditions of access* for the provision of *negotiated transmission services* under this framework and use reasonable endeavors to commence, progress and finalise negotiations in a timely manner. Where the *negotiated transmission services* sought by the *Service Applicant* relate to *connection*, VENCorp will comply with any applicable time periods required under clause 5.3 of the National Electricity Rules.

2. VENCorp and Service Applicants to provide information

Subject to any confidentiality obligations owed by either VENCorp or *Service Applicant* to any third party:

- VENCorp will provide all such commercial information as a *Service Applicant* may reasonably require to enable the *Service Applicant* to engage in effective negotiation with VENCorp for the provision of negotiable services; *negotiated transmission services*, including a description of the nature of the *negotiated transmission service* and details of what VENCorp would provide as part of that service; and

- A *Service Applicant* shall provide all such commercial information as VENCorp may reasonably require enabling VENCorp to engage in effective negotiation with the *Service Applicant* for the provision of *negotiated transmission services* including a detailed description of the negotiable service required.

3. Confidentiality

Each of VENCorp and a *Service Applicant* shall observe any confidentiality restrictions placed on commercial information provided to it by the other party under paragraph 2, in accordance with clause 6A.9.6(a)(12) or (b)(2) of the National Electricity Rules. This obligation :

- shall not apply to the extent that VENCorp or the *Service Applicant* is required to disclose the confidential information under any law, Rules or regulation, or any requirement of a Government Minister or body; and
- does not limit any obligations of VENCorp and any *Service Applicant* under clause 5.3.8 of the National Electricity Rules.

4. Cost of the negotiated transmission services

VENCorp shall inform a *Service Applicant* of the reasonable costs, or change in costs, of VENCorp providing *negotiated transmission services* to the *Service Applicant*, and shall demonstrate to the *Service Applicant* that these reflect the costs, or change in costs, of VENCorp providing the *negotiated transmission services*.

5. Dispute Resolution

All disputes concerning negotiations for *negotiated transmission services* shall be dealt with in accordance with Part K of Chapter 6A of the National Electricity Rules.

6. Payment of VENCorp's direct expenses

A *Service Applicant* shall pay VENCorp's direct expenses incurred in processing its application for *negotiated transmission services*. Those expenses must be reasonable and are payable by a *Service Applicant* when reasonably required by VENCorp.

Generally, VENCorp will require a *Service Applicant* to pay a fee on application on account of VENCorp's anticipated reasonable direct expenses associated with processing the application to provide *negotiated transmission services*. This application fee will be a minimum of $15,000.

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7. Potential impact on other Network Users

VENCorp will determine the potential impact on other *Transmission* Network Users of provision of a *negotiated transmission service*. VENCorp will notify and consult with any affected *Transmission* Network Users to ensure that the provision of a *negotiated transmission service* does not result in non-compliance with obligations in relation to those *Transmission* Network Users under the National Electricity Rules or under contractual arrangements with VENCorp.

9. VENCorp and Network User to comply with Framework

VENCorp and *Service Applicant* shall comply with the terms of this negotiating framework when negotiating for the provision of a *negotiated transmission service*. However, in the event of any inconsistency between this framework and the requirements of Chapters 4, 5 or 6A of the National Electricity Rules, those requirements will prevail over the relevant terms of this framework.

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Attachment 4 Committed Augmentations (Confidential)

Attachment 5 Summary of Network Constraints and Likely Augmentations to address the constraint

Predominantly Load Driven Augmentations

Constraint	Possible Network Solution	Estimated Cost ($millions) real excluding GST	Estimated Timing	Comments
Security of supply to radially connected Springvale, Heatherton and Malvern terminal stations	Malvern-Heatherton 220 kV underground cable (or a overhead line - if feasible at a lower cost)	43.8	Around 2012	Timing subjected to alternative contingency arrangement by Distribution businesses and feasibility of network options
Outage of an eastern metropolitan 500/220 kV transformer overloads the remaining eastern metropolitan transformer, Thomastown-Ringwood 220 kV circuit and Thomastown-Templestowe 220 kV circuit Outage of Rowville-Ringwood 220 kV circuit overloads Thomastown-Ringwood 220 kV circuit	One 1,000 MVA 500/220 kV transformer at Templestowe or Ringwood	43.8	Around 2012	Timing and location subjected to further assessment
Wind generation located in state grid.	SVC in State Grid	25.0	Around 2011	Does not appear in 2006 EAPR. Need identified following a study on the impact of new wind farms
Network reactive support in the metropolitan area	500 to 2,000 MVAr Reactive Support	25.0	From 2011 to 2014	Location and amount of capacitor banks depend on development of the network
Fault level issues	Fault limiting devices, series reactors and upgrade selected 220 kV switchgear in the metropolitan area	19.0	From 2011 to 2014	
Line terminations, secondary equipment and dynamic system and supply of quality monitoring equipment.	Miscellaneous works in metropolitan area	19.0	From 2011 to 2014	
Line terminations, secondary equipment and dynamic system and supply of quality monitoring equipment	Miscellaneous Works in state grid	12.5	From 2011 to 2014	
Network reactive support in the State Grid area	200 to 600 MVAr Reactive Support	10.0	Ongoing as required	Location and amount of capacitor banks depend on development of the network

Constraint	Possible Network Solution	Estimated Cost ($millions) real excluding GST	Estimated Timing	Comments
South Morang–Thomastown 220 kV circuit for outage of a parallel circuit	Establishment of South Morang 220 kV terminal station and cutting of existing Rowville to Thomastown 220 kV circuit into South Morang 220 kV bus to form the third South Morang to Thomastown 220 kV circuit	6.3	At time of Interconnection upgrade by 600 MW or around 2012	In the 2006 EAPR this appears at a higher cost, but it has now been reduced as there are elements which are considered to be funded augmentations.
Ballarat to Bendigo circuit overload for outage of the Bendigo to Shepparton line	Ballarat to Bendigo 220 kV line upgrade to 75°C conductor temperature	4.3	Around 2013	
Fishermans Bend to West Melbourne circuit overload for outage of a parallel circuit	Replacement of inter-plant connections and primary plant of Fishermans Bend to West Melbourne line	3.8	Around 2012	
Keilor to West Melbourne-circuit overload for outage of a parallel circuit	Replacement of circuit breakers and inter-plant connections at Keilor and West Melbourne of the Keilor to West Melbourne 220 kV lines	3.8	Around 2012	SP AusNet scheduled to replace the limiting plants by 2008/09 as part of asset refurbishment program
Ballarat to Moorabool circuit overload for outage of parallel Ballarat to Moorabool circuit at high load.	Uprate the Ballarat to Moorabool No 1 circuit to 75°C conductor temperature	4.3	Around 2010	
DSM & QOSM equipment as required by NEMMCO		2.0	Around 2008	
Geelong to Moorabool 220 kV circuit overload for outage of a parallel circuit	Upgrade terminal station plants at Moorabool and Geelong	1.3	Around 2012	
Rowville-Springvale circuit overload for outage of a parallel circuit.	Uprate Rowville-Springvale line to 82°C	1.3	Around 2012	
Eildon-Thomastown line for outage of South Morang to Dederang line	Wind monitoring scheme on Eildon-Thomastown 220 kV line	0.8	Around 2012	
Rowville to Richmond circuit overload for outage of parallel circuit	Wind monitoring scheme on the Rowville-Richmond line	0.6	Around 2012	Level of overload reduced if CitiPower transfer part of Richmond load to Malvern, following refurbishment of Malvern by SP AusNet
Ballarat to Bendigo circuit overload for outage of the Bendigo to Shepparton line	Wind monitoring scheme on the Ballarat to Bendigo circuit	0.6	Around 2010	
Rowville to Malvern circuit overload for outage of a parallel circuit	Wind monitoring scheme on the Rowville-Malvern lines	0.5	Around 2012	CitiPower plans to transfer about 100 MW load from Richmond to Malvern, following refurbishment of Malvern by SP AusNet

Constraint	Possible Network Solution	Estimated Cost ($millions) real excluding GST	Estimated Timing	Comments
Springvale-Heatherton circuit overload for outage of a parallel circuit.	Wind monitoring scheme on the Springvale-Heatherton lines	0.5	Around 2012	

Predominantly Generator Driven Augmentations

Predominantly Latrobe Valley Generation

Constraint	Possible Network Solution	Estimated Cost ($millions) real excluding GST	Estimated Timing	Comments
Inadequate thermal capacity of Loy Yang to Hazelwood 500 kV lines	Fourth 500 kV line from Loy Yang to Hazelwood	37.5	At the time of about 500 MW new generation connected at Loy Yang	Timing depends on generation development behind the constraint and subject to availability of easement.
Outage of a Hazelwood 500/220 kV transformer overload the parallel transformers	Additional 220/500 kV transformation at Hazelwood and fault level mitigation	27.5	At the time of additional new generation connected at Hazelwood or Jeeralang 220 kV	Timing depends on generation development behind the constraint
Network reactive support in the metropolitan area	500 to 2,000 MVAr Reactive Support	25.0	Ongoing as required	Location and amount of capacitor banks depend on development of the network
Thermal loading of lines in the Malvern area	220kV line uprate to 82deg Rowville to Malvern	21.3	Contingent on the transfer of 70MW of load from Richmond Terminal Station by Citipower	
Dederang 330/220 kV transformers overload for an outage of a parallel transformer	Fourth Dederang 330/220 kV transformer	13.8	At time of Interconnection Upgrade by 180 MW	
Inadequate thermal capacity on Latrobe Valley (LV) to Melbourne 500 kV lines	Upgrade terminations and circuit breaker thermal ratings at Hazelwood	7.5	At the time of about 500 MW new generation at LV 500 kV	Timing depends on generation development behind the constraint
Network reactive support in the State Grid area	200 to 600 MVAr Reactive Support	5.0	Ongoing as required	Location and amount of capacitor banks depend on development of the network

Predominantly South West Generation

Constraint	Possible Network Solution	Estimated Cost ($millions) real excluding GST	Estimated Timing	Comments
Outage of a Hazelwood 500/220 kV transformer overload the parallel transformers	Additional 220/500 kV transformation at Hazelwood and fault level mitigation	27.5	At the time of additional new generation connected at Hazelwood or Jeeralang 220 kV	Timing depends on generation development behind the constraint
Thermal loading of lines in the Malvern area	220kV line uprate to 82deg Rowville to Malvern	21.3	Contingent on the transfer of 70MW of load from Richmond Terminal Station by Citipower	
No suitable connection point for possible large generators around Mortlake	Establishment of a 500 kV terminal station near Mortlake to connect to the existing Moorabool-Heywood 500 kV lines	15.0	At the time of additional new generation connection to 500 kV in the South West corridor	In the 2006 EAPR this appears at a higher cost but it has been reduced as there are elements which are now considered to be funded augmentations
Dederang 330/220 kV transformers overload for an outage of a parallel transformer	Fourth Dederang 330/220 kV transformer	13.8	At time of Interconnection Upgrade by 180 MW	
Network reactive support in the State Grid area	200 to 600 MVAr Reactive Support	5.0	Ongoing as required	Location and amount of capacitor banks depend on development of the network

Predominantly Increase in import from Snowy/NSW

Constraint	Possible Network Solution	Estimated Cost ($millions) real excluding GST	Estimated Timing	Comments
Inadequate thermal capacity of Loy Yang to Hazelwood 500 kV lines	Fourth 500 kV line from Loy Yang to Hazelwood	37.5	At the time of about 500 MW new generation connected at Loy Yang	Timing depends on generation development behind the constraint and subject to availability of easement.
South Morang 330/220 kV transformer overload for a outage of a parallel transformer	Third 700 MVA 330/220kV South Morang transformer	25	At time of Interconnection Upgrade by 600 MW	
Thermal loading of lines in the Malvern area	220kV line uprate to 82deg Rowville to Malvern	21.3	Contingent on the transfer of 70MW of load from Richmond Terminal Station by Citipower	
Murray to Dederang 330 kV line overload for outage of parallel circuit	60-65% series compensation on Wodonga to Dederang and/or Wodonga-Jindera 330 kV lines & 150 MVAr shunt cap bank at Wodonga/Dederang	15.0	At time of Interconnection Upgrade by 600 MW	
Dederang 330/220 kV transformers overload for an outage of a parallel transformer	Fourth Dederang 330/220 kV transformer	13.8	At time of Interconnection Upgrade by 180 MW	
South Morang to Dederang 330 kV line and series capacitors overload for outage of parallel circuit	Uprate of South Morang to Dederang 330 kV lines and increase in rating of South Morang to Dederang series compensation to match line uprate	9.3	At time of Interconnection Upgrade by 600 MW	Subject to further investigation of increased operating voltage limits.
Eildon-Thomastown line for outage of South Morang to Dederang line	25% series compensation on the Eildon to Thomastown 220 kV line	8.8	At time of Interconnection Upgrade by 600 MW	
Inadequate thermal capacity on Latrobe Valley (LV) to Melbourne 500 kV lines	Upgrade terminations and circuit breaker thermal ratings at Hazelwood	7.5	At the time of about 500 MW new generation at LV 500 kV	Timing depends on generation development behind the constraint
Dederang-Glenrowan circuit overload for outage of a parallel circuit	Installation of a phase angle transformer on the Bendigo-Shepparton 220 kV line	6.3	At the time of Interconnection Upgrade by 600 MW or around 2013	

Constraint	Possible Network Solution	Estimated Cost ($millions) real excluding GST	Estimated Timing	Comments
Bendigo-Fosterville-Shepparton circuit overload for outage of a Ballarat to Bendigo circuit	Bendigo-Fosterville-Shepparton 220 kV line upgrade to 90°C	6.3	At time of Interconnection Upgrade by 600 MW	
Reactive support at Wodonga and Dederang	Installation of a 150 MVAr capacitor bank at Wodonga and control & communications	5.0	At time of Interconnection Upgrade by 180 MW	
Network reactive support in the State Grid area	200 to 600 MVAr Reactive Support	5.0	Ongoing as required	Location and amount of capacitor banks depend on development of the network
Eildon-Thomastown line for outage of South Morang to Dederang line	Upgrade of Eildon to Thomastown 220 kV line	3.0	At time of Interconnection Upgrade by 600 MW or around 2013	

Predominantly Metropolitan and State Grid Generation

Constraint	Possible Network Solution	Estimated Cost ($millions) real excluding GST	Estimated Timing	Comments
Outage of a Hazelwood 500/220 kV transformer overload the parallel transformers	Additional 220/500 kV transformation at Hazelwood and fault level mitigation	27.5	At the time of additional new generation connected at Hazelwood or Jeeralang 220 kV	Timing depends on generation development behind the constraint
Fault level issues	Fault limiting devices, series reactors and upgrade selected 220 kV switchgear in the metropolitan area	25.0	Ongoing as required	
Wind generation located in state grid.	SVC in State Grid	25.0	As required	Does not appear in 2006 EAPR Need identified following a study on the impact of new wind farms
Thermal loading of lines in the Malvern area	220kV line uprate to 82deg Rowville to Malvern	21.3	Contingent on the transfer of 70MW of load from Richmond Terminal Station by Citipower	
Dederang 330/220 kV transformers overload for an outage of a parallel transformer	Fourth Dederang 330/220 kV transformer	13.8	At time of Interconnection Upgrade by 180 MW	
Fault level issues	Fault limiting devices, series reactors and upgrade selected 220 kV switchgear in the state grid	12.5	Ongoing as required	

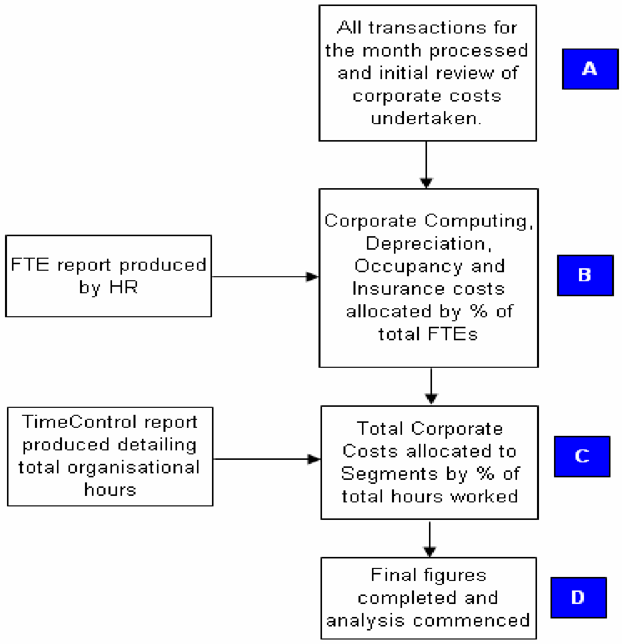
Export Driven Augmentations

Constraint	Possible Network Solution	Estimated Cost ($millions) real excluding GST	Estimated Timing	Comments
Outage of a Heywood-South East 275 kV circuit overloads the parallel circuit	Third Heywood-South East 275 kV circuit	68.8	At the time of 300 MW additional export to SA via Heywood	
South Morang 500/330 kV transformer overload with increased export to Snowy/NSW	Second 1,000 MVA 500/330 kV transformer at South Morang	43.8	At the time of increase in export to Snowy/NSW	
Reactive support and voltage control in the Heywood area	One SVC at Heywood (+200/-200 MVAr)	27.5	At the time of 300 MW additional export to SA via Heywood	Timing with increased export to SA or increased load at Portland
Outage of a Heywood 500/275 kV transformer overloads the parallel transformer	Third 370 MVA 500/275 kV Heywood transformer and 500 kV bus-tie at Heywood	22.5	At the time of 300 MW additional export to SA via Heywood	
Transient stability limit for a fault on Hazelwood-South Morang 500 kV line	A 500 MW, 500 kV braking resistor at Loy Yang	8.8	At the time of 150-200 MW increase in export to Snowy/NSW or 300 MW increase in export to SA (Scenario 5)	

Attachment 6 Operating and Planning Expenditure Cost Categories

Cost Category	Description
Labour	Includes salaries and wages and on-costs
Contracted Services	Relates to electricity transmission licence fee payable to the Essential Services Commission plus a share of VENCorp's insurance costs. Insurance costs are allocated on the full-time equivalents (FTEs) basis detailed below.
Computing and communications	Includes direct electricity computing costs such as licences, software and maintenance and direct landline and mobile phone costs. Also includes an allocation of corporate computing costs on an FTE basis.
Consultancies and contractors	Consultancies includes internal audit costs and legal costs plus individual projects such as Vision 2030 and the Easement review. Contractors are used to fill short term vacancies or provide an additional resource when there are short term demands.
Vehicles & Travel	Running costs associated with Manager's vehicles. An allowance has been made for 4 vehicles.
Occupancy	Allocation of organisation costs based on the number of FTE in the electricity segment as a percentage of the total organisation FTEs.
Administrative Costs	Includes costs such as printing, Fringe Benefits tax and memberships.
Depreciation & Amortisation	Depreciation on specific electricity assets, such as servers and 4 motor vehicles, plus an allocation of depreciation costs on the FTE basis.
Service Department Allocations	Corporate costs are those costs that are not directly incurred by other segments of the business (ie. gas, electricity and contestability) and include costs associated with the Board, administration, general management, communications, finance, insurance, legal, business systems, risk management and human resources. The monthly corporate costs are allocated on the basis of: • Full Time Equivalents (FTEs) per segment as a percentage of total organisational FTEs; and • The number of hours worked in a segment as a percentage of total organisational hours. With respect to FTE's per segment, Corporate costs associated with Computing, Depreciation, Insurance and Occupancy are allocated on the basis of FTEs and are included in the costs of those specific line items. The rationale for this treatment is that these costs do not fluctuate in line with the number of hours worked. Following the completion of the allocations based on FTEs, the remaining corporate costs are allocated based on the number of hours worked in a segment as a percentage of total hours worked in the organisation. The rationale for this treatment is that the number of hours worked by a particular segment of the business will require a proportionate amount of service delivery from the Corporate department. Therefore, the more hours of work in a segment, the more time and resources the Corporate department assigns to this segment and vice versa. This is set out in the flow chart below:

<table>
<tr><th>Cost Category</th><th>Description</th></tr>
<tr><td></td><td>



Summary

A - Ensure all journals are completed before allocating fixed overheads
B - Obtained FTE report from Human Resources and calculate % FTE per section code. Multiply section % against total expenditure and journal to respective section codes.
C - Ensure that Step B has been completed before moving on to this step. Obtain timecontrol report of total organisational hours by Segment and calculate % hours per segment. Multiply the balance of corporate expenditure by % per Segment
D - Check final figures for reasonableness and commence analysis.

Information on hours worked is extracted from VENCorp's time recording system.

All VENCorp employees have access to the Timecontrol system and are required to complete timesheets on a weekly basis.

All employees are required to allocate their time worked to the different functions of the business

- Wholesale Gas
- Electricity
- Contestability; or
- Corporate.

Data is extracted from the TimeControl system at month end to determine the percentage of time worked in each function of the business. These percentages are then used to allocate Corporate Department costs to the other segments of the business.

</td></tr>
</table>

Attachment 7 Comparison of actual and allowed forecast expenditure by expenditure category

	$('000) excluding GST																	
	Jan-June 03			2003/04			2004/05			2005/06			2006/07			2007/08		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance	Budget	Forecast	Variance	Budget	Forecast	Variance
Labour	921	1,118	(197)	2,098	2,357	(259)	2,020	2,436	(416)	936	2,636	(1,700)	2,705	2,722	(17)	2,813	2,814	(1)
Contracted Services	107	110	(3)	265	204	61	232	205	27	247	209	38	219	211	8	228	212	16
Computing & Communications	186	253	(67)	336	467	(131)	322	469	(147)	350	479	(129)	616	480	136	600	486	114
Consultancies and contractors	359	287	73	357	534	(177)	627	546	81	690	559	131	1,171	570	601	1,036	582	454
Occupancy	76	84	(8)	150	168	(18)	151	168	(17)	151	168	(17)	174	168	6	182	168	14
Vehicles and Travel	73	81	(8)	116	164	(48)	102	166	(64)	51	174	(123)	56	176	(120)	57	179	(122)
Administrative Costs	17	22	(5)	18	44	(26)	17	44	(27)	73	44	29	110	44	66	114	44	70
Service Department Allocations	647	633	15	1,189	1,318	(129)	1,210	1,320	(110)	805	1,397	(592)	1,197	1,385	(188)	1,195	1,442	(247)
Depreciation & Amortisation	71	129	(58)	120	277	(157)	124	315	(191)	64	378	(314)	79	329	(250)	100	282	(182)
Operating Expenditure	2,457	2,715	(258)	4,649	5,533	(884)	4,805	5,669	(864)	3,367	6,044	(2,677)	6,327	6,085	242	6,325	6,209	116

Attachment 8 Reconciliation Statement

$('000) excluding GST	Forecast 2007/08
Operating Revenue	
TUoS Revenue	350,309
SA Electranet	6,500
Network Charges	(386,400)
Settlement Residue	35,000
Consultancy & Other	0
TOTAL REVENUE	5,409
OPERATING EXPENDITURE	5,029
Depreciation & Amortisation	100
Corporate Recovery	1,195
TOTAL EXPENDITURE	6,324
EARNINGS BEFORE FINANCING	(915)
Interest Income	918
Finance Charges	3
SURPLUS / (DEFICIT)	0
Surplus Cf	24,607
Accumulated Surplus	24,607

Attachment 9 Availability Incentive Scheme

1. Objectives

The Availability Incentive Scheme (AIS) is a simplified alternative to a fully market based approach to measuring and incentivising network owner performance. The scheme is in place with network owners, including SP AusNet, with whom VENCorp has contracted with, and is generally tailored to suit the particular transmission service. The scheme aims to provide economic signals to network owners which:

- encourage network owners to seek plant outages at times when the expected cost[20] to wholesale electricity market participants of an outage is minimal;
- encourage asset management practices which assist in ensuring that the actual cost borne by market participants due to unavailability of transmission assets is minimised;
- in conjunction with benchmark / target performance standards for network availability, encourage asset management[21] practices which assist in delivering performance expectations over the long run;
- provide an effective commercial incentive to network owners to manage their business in a manner which results in the optimisation of the actual and expected costs of transmission losses, constraints and load shedding (due to unavailability of its plant) over the long run and having regard for the cost of investing in, and maintaining transmission assets; and
- is consistent with the principle that network owners should be exposed to risks which are most effectively and efficiently managed by themselves.

2. Pricing principles

The scheme operates by reducing the network payments made by VENCorp to network owners based on the availability of each transmission element.

An hourly rate is applied for each element of the shared transmission network based on its value to the network, i.e. based on load at risk, cost of rescheduled generation and incremental transmission losses assessment. A separate rate is calculated for peak (i.e. summer), intermediate (i.e. winter) and off-peak hours.

The annual expected cost of the scheme can be calculated by multiplying the hourly rate for each element by the number of hours in a year that each element is expected to be unavailable. A weighting is applied to peak, intermediate and off-peak time periods to calculate the expected costs in each of the periods.

Table A9.1 sets out the outage periods for the AIS

20 This cost includes the sum of costs associated with generation re-scheduling due to transmission constraints, marginal transmission losses and involuntary load shedding.

21 Asset management encompasses asset replacement, refurbishment, replacement, maintenance and any other activity employed by network owners to maintain the operating capability of its assets.

Table A9.1 – Outage Periods

Period	Definition
Peak	Mid Nov – Mid Mar; Weekdays; 1100 – 2200 hrs
Intermediate	1 Jun – 31 Aug; Weekdays; 0700 – 2200 hrs
Off Peak	All other times

The current scheme with SP AusNet valued at $6 million per annum. However, the scheme is designed to be revenue neutral for SP AusNet based on historical records and current practices, i.e. if SP AusNet made no changes to the way it manages outages it would repay to VENCorp in rebates the full amount of the annual value. However, consistent with the objectives of the scheme, improvements in network management practices are anticipated to be delivered within the period of the scheme. Operating and maintenance practice efficiency gains achieved would be inherent in the basis applied to restrike the Annual Value as in the present instance, where the efficient practices achieved to date will a key factor in valuing the scheme in the coming regulatory period).

Table A9.2 details the expected total annual rebates to apply under the amended scheme which is set out in the Network Agreement between VENCorp and SP AusNet.

Table A9.2 – Expected Total Annual Rebates

Component	Annual Rebate
Planned maintenance	$3,249,507
Unplanned maintenance	$1,283,484
Minor plant failure (fault and forced outages)	$433,057
Trip checks	$31,314
Construction	$457,957
Major plant failure	$553,759
Total	$6,000,000

3. Operation of the scheme

- Rebates will apply to all outages from any cause of node to node network elements, except defined Force Majeure events and other excluded causes.

- To reflect that availability of elements is of increased criticality when parallel elements are un-available, peak period rates will apply for simultaneous outages of interdependent network elements.

- In order to contain the risk and therefore the price of the scheme to an economic level, there is a cap per event, and an annual cap on the scheme.

Table A9.3 outlines the outage categories and.

Table A9.3 – Outage Categories

Component	Outage Type
Planned maintenance	Planned activity derived from SP AusNet's annual maintenance budget
Unplanned maintenance	Minor defects not associated with planned maintenance activities (i.e. repair of oil leaks)
Minor plant failure (fault and forced outages)	Protection operations, control centre intervention alarms and failure of components replaced "off the shelf"
Trip checks	Tests on circuit breakers or protection equipment
Construction	SP AusNet's capex replacement program
Major plant failure	Catastrophic failure of an element, requiring rebuilding or replacements

4. Modifications

The current scheme allows for adjustments to the Outage Rebate rates if there are any augmentations to the high voltage grid (this includes the addition of new circuits, transformers or items of reactive plant, the reconfiguration of any part of the high voltage grid or replacement or enhancement of components of the high voltage grid). Any such revised rates require that the aggregate amount of outage rebates to be paid by SP AusNet under the scheme in any year, as calculated by applying the outage rebate rates, is the same as that which is likely to be paid in respect of that year, applying the outage rebate rates prior to such alteration.