

2014 NETWORK PRICE DETERMINATION

Initial Regulatory Proposal
1 July 2014 to 30 June 2019

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Foreword from the Managing Director

Our modern society has become dependent upon the continuous supply of high quality electricity upon demand. The Northern Territory has entered an exciting period of rapid growth and gradual restructuring of the Northern Territory's economy based on expansion in the resources, defence and tourism industries. Our electricity network must develop to support this growth, since a secure and reliable electricity network is fundamental to the Northern Territory's economic development.

The third regulatory control period from 2009-14 bore witness to significantly increased investment in the network. This was driven by equipment failures at Casuarina Zone Substation in 2008 that exposed shortcomings in Power Networks' asset management practices. The incident at Casuarina Zone Substation is now behind us, and importantly, essential lessons on asset management practices have been learnt. This was the turning point for Power Networks to introduce wide reaching changes in all aspects of asset management, which are well under way.

As we enter the fourth regulatory control period, the Power Networks business must rise to a number of challenges and priorities:

- In recent years, growth in electricity demand and the number of new customer connections has been high. Power Networks forecasts this growth to be sustained for several years as economic development continues apace. This in turn requires additional investment by Power Networks to increase capacity and provide new connections, and be positioned to support key infrastructure projects.
- Power Networks must operate on a commercial footing and provide returns to its owner that are commensurate with those of a private sector business. An essential part of this will be achieved by keeping costs to efficient levels by the prudent management of assets. This proposal therefore focuses on continuing the implementation of modern asset management strategies and practices.
- Power Networks must provide a service that customers have confidence in and recognise as providing value. We accept that there is some room to improve the security and reliability of our electricity supply and that our existing practices could be refined. We have proposed increases to capital and operating expenditure that will achieve this reliability improvement through targeted asset replacements, the implementation of an Integrated Distribution Management System, and an enhanced vegetation management program.
- Power Networks' workers are our most valuable asset and their safety and wellbeing remains paramount. In formulating this proposal, no short cuts have been taken that would compromise existing OH&S procedures and practices.

In relation to the significant price increases that are proposed in this document, it must be noted that Power Networks' costs during the current regulatory control period are well in excess of its tariffs. The recent network tariff pass-through of costs associated with the Casuarina incident only partly addressed this funding shortfall.

The National Electricity Rules based approach implemented by the Utilities Commission for this determination uses a bottom-up assessment of efficient costs. This has highlighted the need for a further significant tariff increase to enable Power Networks to provide a safe, secure and reliable supply of electricity on a commercial footing, rather than increasing levels of debt that must be paid off by taxpayers or future generations of customers.

I commend this regulatory proposal, together with its supporting documents, as providing the necessary rigour and robust justification of Power Networks' strategy and proposed approach to planning, developing and managing its network assets during the fourth regulatory control period.

We look forward to engaging with the Utilities Commission during the next stage of this important process.

John Baskerville
Managing Director

1 Introduction

This document and its attachments comprise Power Networks' Initial Regulatory Proposal (Proposal) to the Utilities Commission (Commission) for the regulatory control period from 1 July 2014 to 30 June 2019. The Proposal is supported by:

- A memory stick containing copies of additional detailed documentation to substantiate the information presented in this main submission and its attachments;
- Other specific responses according to the requirements of the Regulatory Information Notice (RIN) issued on 9 April 2013, provided at Confidential Attachment 18; and
- An Overview Paper accompanying the Proposal, which summarises the Proposal for electricity customers and includes a description of key risks and benefits of the Proposal for electricity customers, provided at Attachment 1.

This main submission document has been prepared specifically for the current regulatory process.

Much of the detailed information that accompanies this proposal, including that contained in the RIN templates, was submitted to the Commission in stages during the period from April to August 2013. This earlier information was submitted on the basis that it was preliminary and, where necessary, would be updated with the submission of this Proposal. The complete RIN templates and much of the previously submitted material have been resubmitted with this Proposal. Where changes have been made to previously submitted material, the changes have been identified and the reasons for the change are explained.

The information contained on the memory stick, although forming part of the Proposal, includes documents and data that are part of Power and Water's routine business documentation, and are therefore subject to ongoing change and development.

Whilst Power Networks is committed to an open and transparent regulatory process, some Attachments and supporting material forming part of this Proposal are considered commercial-in-confidence and have been indicated as confidential. Within this IRP, confidential parts to be removed from the public version have been blacked out.

1.1 Executive summary

Power Networks is proposing an initial revenue increase (Po adjustment) in 2014/15 of 57.2 per cent. This proposed Po has been based on an independent asset valuation recently prepared by Sinclair Knight Merz (SKM), as opposed to the Commission's preferred roll-forward of the initial value of the regulatory asset base of \$350 million as at 1 July 2002. However, both sets of data have been submitted to the Commission.

Power Networks' electricity network cost 'building blocks' for the 2014/15 regulatory year comprise of a return on assets of \$81.9 million, depreciation (return of capital) of \$27.7 million, operating and maintenance costs of \$113.6 million and a levelised carry-over amount of \$7.4 million, as calculated by the NT Revenue Model.

Power Networks' revenue from standard control network services in 2013/14 is expected to be \$142.0 million. Power Networks' required revenue (or Maximum Allowable Revenue (MAR) is \$229.03 million in 2014/15. Therefore, Power Networks proposes that the Po adjustment required to network revenue for the fourth regulatory control period is 57.2 per cent.

Using the Commission's preferred roll-forward of the initial value of the regulatory asset base of \$350 million as at 1 July 2002 would result in a Po adjustment of 50.6 per cent. This is inconsistent with the provision of a return on efficient capital investment undertaken by the network provider to maintain or extend network capacity that is commensurate with the commercial and regulatory risks involved, as is required by clause 68(e) of the Electricity Networks (Third Party Access) Code.

Once approved, Power Networks' proposed Po adjustment will mean that there is a significant increase in the weighted average network component of electricity prices. This is because the Po and weighted average network tariffs set in 2009 were not reflective of actual expenses over the third regulatory period, and there was a significant gap between Power Networks' costs and the network tariffs allowed by the Commission. This is because the Commission's 2009 Networks Price Determination:

- Utilised a Total Factor Productivity (TFP) methodology to derive allowable revenue, which did not take account of a realistic level of (then) future costs; and
- Applied benchmarking studies that aggressively reduced the allowed operating expenditure to less than Power and Water was required to spend over the period.

In contrast, Power Networks' prudent and efficient capital and operating expenditure increased significantly faster than what was allowed for in the 2009 Networks Price Determination. Consequently, a real increase in the weighted average network tariff is now required.

1.2 Regulatory context

In common with many other network businesses, Power Networks is subject to a regulatory regime designed to establish prices for access to the network at levels that allow for recovery of no more than the cost of providing standard control services.

The Northern Territory is not a party to the National Electricity Market (NEM) arrangements. Rather, the Electricity Networks (Third Party Access) Act and accompanying Code (the Code) sets out the principles by which Power Networks'

revenues are regulated and establishes the arrangements under which the Commission regulates network revenues¹.

The 2014 Networks Price Determination is for the fourth five-year regulatory control period since the establishment of these arrangements. It differs from previous regulatory determinations in that the Commission has decided to use, where practicable, the approach used by the Australian Energy Regulator (AER) and the application of those parts of Chapter 6 of the National Electricity Rules (the Rules) in relation to electricity distribution network businesses in the NEM that are consistent with the Code².

The adoption of the AER and Rules process means there are some significant differences between the process followed for the 2014 Networks Price Determination and that followed in the 2009 Networks Price Determination. The principal differences are as follows:

- The Rules process for the making of a determination is largely being followed by the Commission, albeit to a compressed timeframe;
- The Commission will make a determination using the accrual building block process established in the Rules. This is a fundamental change from the Total Factor Productivity (TFP) approach used in 2009. Power Networks welcomes this change for the greater transparency on regulatory decision making that it will provide; and
- The Commission has followed the RIN requirements established by the AER (based on the RIN for the AER's most recent Aurora review)³. This involves the provision of a great deal of detailed information to support the regulatory decision. Power Networks' systems were in some instances unable to provide this level of detail.

The Commission has in some instances needed to adapt the Rules process and AER approach for Power Networks' circumstances. The main areas of adaptation were as follows:

- The adoption of a multi-stage approach to the submission of information under the RIN, with monthly instalments over the period from 29 April to 16 September 2013. This staged approach and some necessary variations to it, are discussed in section 1.3 below; and
- A change to a pre-tax framework from the post-tax framework used by the AER. This change was necessary as Power and Water maintains its Tax Asset Base (TAB) for the Corporation as a whole and a Power Networks' TAB could not be created and verified at short notice. This in turn necessitated the

¹ *Northern Territory of Australia, Electricity Networks (Third Party Access) Act*, as in force at 1 August 2012.

² Utilities Commission, 2014-2019 Network Price Determination Framework and Approach Decision Paper, November 2012, p. 1.

³ Utilities Commission, Regulatory Information Notice under Section 25 of the *Utilities Commission Act* and Clause 22 of Network Licence, April 2013.

modification of the AER's Post Tax Revenue Model (PTRM) used for calculating the allowable revenue. The resultant modified model has been termed the NT Revenue Model (NTRM).

1.3 Variation to information previously provided under the staged submission approach

The Commission and Power and Water agreed to a staged approach to the provision of information for the 2014 Networks Price Determination.

In the RIN issued by the Commission, the Commission acknowledged that a staged approach may lead to inconsistencies between information prepared at different stages and that revised information may be submitted where inconsistencies arise from this staged approach⁴.

The material variations that have been made to the information previously submitted to the Commission as part of the staged approach are set out in Table 1.

Table 1 – Variations to the RIN staged approach

Information	Variation
Stage 2 – Network Services Classification	Remove reference to MWh thresholds in reference to meter types in anticipation of the Interval Meter Roll-out Program in the forthcoming regulatory period.
Stage 2 – RIN Templates 6.3, 6.4 and 6.5 (Demand Forecast)	Updated for 2013/14 Demand Forecast to provide the latest available information.
Stage 3 – Power Networks Cost Allocation Method (CAM)	CAM has been updated to include a compliance section.
	CAM has been updated to reflect: <ul style="list-style-type: none"> • 2013/14 budget corporate allocations; • Power and Water's recent organisational restructure; and • A change to the processing of cost allocations within Power Networks.
Stage 3 – RIN Templates 3.1 and 5.4 (capex forecast and associated justification)	Capex forecasts updated for revised materials and labour cost escalators.
	Capex forecasts updated for*: <ul style="list-style-type: none"> • New projects that have only recently been approved under Power and Water's capital governance process; • Previously submitted projects that have been materially revised due to a change in inputs; and • Previously submitted projects that have had a change in timing.
Stage 4 – RIN Templates 2.1,	Opex forecasts updated for revised materials and labour cost escalators.

⁴ Utilities Commission, Regulatory Information Notice, Schedule 3, section 1.2, April 2013.

Information	Variation
2.2, 2.4, 5.1 and 5.4 (opex forecast and associated justification)	Opex forecasts updated for*: <ul style="list-style-type: none"> • The inclusion of recently approved step changes in forecast opex; and • Revisions made to forecast step changes in opex.
* Specific revisions made to the projects and programs are outlined in the individual revised BNIs and Justification Papers listed at Confidential Attachment 23 and Confidential Attachment 24.	

Further information regarding specific project variations has been provided to the Commission in the confidential Proposal.

The Commission has only recently approved the electricity service standard targets under the 2012 NT Electricity Standards of Service Code (approved on 12 July 2013), and Power Networks is currently reviewing its proposed reliability capex, vegetation management program, unplanned corrective maintenance and Guaranteed Service Level (GSL) payments forecast to determine the impact. Power Networks will update its capex and opex forecasts in its Revised Regulatory Proposal to reflect the recently approved targets.

1.4 Power Networks' Initial Regulatory Proposal

Power Networks' regulatory proposal follows the pattern established in the NEM. The regulatory proposal constitutes the following information and documents:

- This regulatory proposal document, to be published following the Commission's verification of its compliance with the RIN requirements;
- The non-confidential attachments to this document listed in section 17.5;
- The confidential attachments to this document listed in section 17.6;
- Confidential material submitted to the Commission in response to the RIN in documentary form and as spreadsheet templates;
- Confidential supplementary information in documentary form and as spreadsheet models provided to the Commission to assist their consultant's review of the proposal;
- Completed models: the Regulatory Asset Base (RAB) Roll Forward Model (RFM) and the NT Revenue Model (NTRM).

Power Networks has submitted this material as the basis for the Commission to make its 2014 determination of revenues for the 2014-19 regulatory control period.

1.5 Compliance of the Initial Regulatory Proposal

To assist the Commission in assessing the compliance of this document, its attachments and the associated material with the RIN, Power Networks has mapped the sections of the Proposal to the requirements of the RIN.

Section 17.4 provides details of how compliance with the RIN requirements has been documented.

1.6 Key Assumptions

The capital and operating expenditure forecasts detailed in this Proposal are based on the range of assumptions detailed in this Proposal. These assumptions are based on all available information at the time of preparing the Proposal.

In accordance with the RIN, Power and Water's Board of Directors have certified these assumptions as reasonable.

Global assumptions that apply to this Proposal are as follows:

- No change to Power and Water's existing structure that would materially affect costs;
- No material amendments to the legislative and regulatory framework, such as the transfer of network regulation functions to the AER. If any such changes occur they will be treated as a cost pass through event.
- The Commission's approval of the proposed Networks Capital Contributions Policy, the Networks Technical Code and Network Planning Criteria, Networks Services Classification, Network Pricing Principles and Networks Cost Allocation Method;
- Real labour and materials cost escalation to increase on average by 2.1 per cent per annum over the regulatory period;
- CPI increases of between 2.4 per cent and 2.8 per cent per annum; and
- Actual demand in the next regulatory control period will not materially deviate from the demand forecast detailed in chapter 6 of this Proposal.

More detailed assumptions are described in this Proposal and are included in the response to RIN Regulatory Template 7.3 provided at Confidential Attachment 18. These assumptions have generally been based on advice from reputable consultants who are well regarded by industry. All advice has taken into account relevant, up-to-date market and industry information.

1.7 Assumptions to be updated in Power Networks' Revised Regulatory Proposal

There are some assumptions in this Proposal that, due to changing circumstances, Power Networks reserves the right to alter in Power Networks' Revised Regulatory Proposal, to be submitted to the Commission in January 2014. These assumptions are:

- Electricity Standards of Service targets: Power Networks has not had sufficient opportunity to assess the impact of the electricity service standard targets recently approved by the Commission under the 2012 NT Electricity Standards of Service Code. These standards will affect the operating and

capital expenditure forecasts. Those expenditure programs will be updated to take account of the Code requirements;

- Debt Risk Premium: The Debt Risk Premium used to estimate the WACC will be determined from a period of market observation close to the date of the Final Networks Price Determination; and
- Cost Escalators: The real cost escalation for external labour in the Northern Territory is considered volatile, and due to the current resources boom Power and Water considers that labour rates may increase in the forthcoming regulatory control period beyond what has been forecast. In addition, there is uncertainty concerning the carbon price mechanism. Power Networks therefore reserves the right to revise the real cost escalation rates for its Revised Regulatory Proposal.

2 Business overview and context

Power and Water is the major provider of electricity, water supply and sewerage services to more than 85,000 customers across the Northern Territory – an area of more than 1.3 million square kilometres.

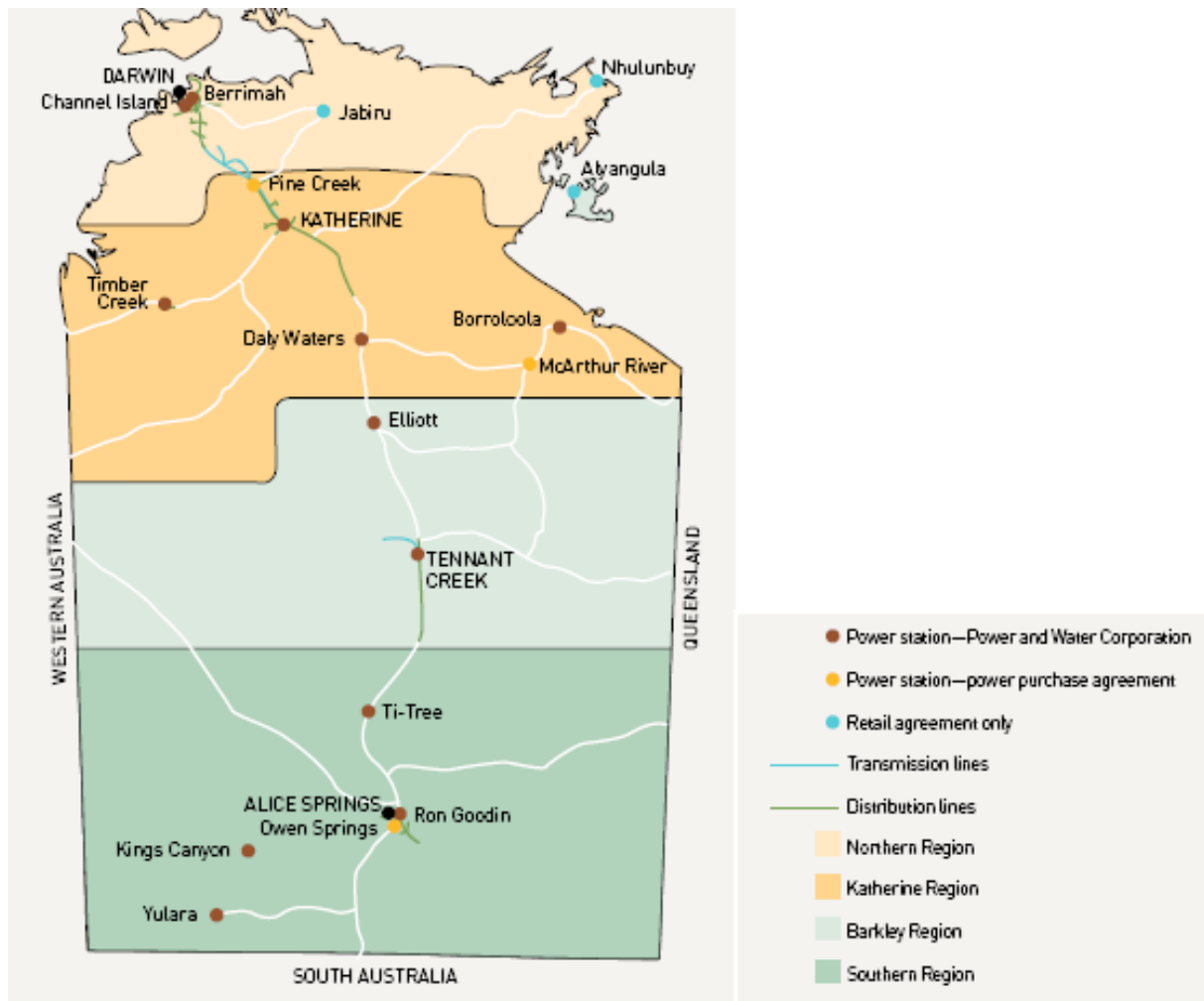
Power and Water is a vertically and horizontally integrated electricity, water and sewerage business, with:

- Electricity Network services, in both regulated and unregulated areas of the Northern Territory through its business unit, Power Networks;
- Electricity Generation services, from both generation facilities that it owns or that are owned by others and contracted to Power and Water;
- System Control services;
- Remote Operations services;
- Water and Sewerage services; and
- Retail services.

These services are delivered across varying environments, from the tropics of the north to the deserts of Central Australia. Power and Water is one of the largest businesses in the Northern Territory, employing more than 1,000 Territorians.

The electricity supply arrangements in the northern Territory are shown in Figure 1

Figure 1 – Electricity supply in the Northern Territory



Power and Water became the Northern Territory's first Government Owned Corporation under the *Government Owned Corporations Act* (GOC Act) on 1 July 2002. In accordance with the GOC Act, Power and Water's objectives are to:

- Operate at least as efficiently as any comparable business; and
- Maximise the sustainable return to the Territory on its investment in Power and Water.

The Shareholding Minister for Power and Water is appointed in accordance with section 8 of the GOC Act. The Shareholding Minister's powers and responsibilities include:

- Setting clear objectives for Power and Water, through the annually negotiated Statement of Corporate Intent (SCI);
- Tabling the SCI and the annual report; and
- Issuing directions after consulting the Board and requesting it to advise whether or not compliance with the direction would be in Power and Water's best interests.

The Board of Power and Water is involved in strategic oversight, establishing the environment in which management will perform, holding management to account, and reporting to the Shareholding Minister. The Board:

- Sets strategic directions, objectives and targets for the business;
- Maintains awareness of the major risks involved in the business, and establishes procedures, systems and controls to manage risks;
- Monitors Power and Water's performance and the performance of management in implementing strategic directions and achieving objectives and targets;
- Ensures compliance in legal matters;
- Reviews its own performance and that of the Managing Director; and
- Reports to the Shareholding Minister.

The agreement between the Board and the Shareholding Minister in relation to expected operational and financial performance is set out in the SCI, which is published each year. This sets out Power and Water's proposed strategies, risks, investment plans and performance targets. The Shareholding Minister approves the budget for the financial year to which the SCI relates and notes the financial projections for the following two years.

The 2013/14 SCI reflects Power and Water's inclusion in the Territory Government's wide ranging initiatives to improve the overall financial position of the Northern Territory through the reduction of annual deficit and accumulated debt levels. Power Networks, in conjunction with all other Power and Water business units, has reviewed its operations to ensure that all possible efficiencies have been identified so that it contributes to Power and Water using its existing and planned resources effectively while maintaining acceptable service delivery to the Northern Territory community.

2.1 Power Networks' role

Power Networks is the largest business unit in Power and Water, with an employment base of approximately 350 positions including trades, apprentices, technical, administration and engineering personnel.

Power Networks has responsibility for planning, building and maintaining reliable electricity networks to transport electricity between electricity generators and electricity consumers in the Northern Territory. Its mission is to achieve this in a safe, reliable, efficient and environmentally sustainable manner.

Power Networks operates under a Network Licence issued by the Commission which authorises it to:

- Own and operate an electricity network within the geographic area specified in Schedule 2 of that Network Licence as set out below; and

- Connect the electricity network to another electricity network, in accordance with the terms and conditions of the Network Licence.

Schedule 2 of the Network Licence lists the regulated electricity network(s) covered by the Licence:

- Darwin (city, suburbs and surrounding rural areas);
- Katherine (township and surrounding rural areas);
- Darwin-Katherine Transmission Line (132kV) which extends from the network 132kV bus at Channel Island Power Station to a 132/22kV substation adjacent to the Katherine Power Station, with a 132/22kV substation at Manton and a 132/66kV substation at Pine Creek;
- Tennant Creek (township and surrounding rural areas); and
- Alice Springs (township and surrounding rural areas).

In servicing the customers in these areas, Power Networks supplies an area which is larger than that supplied by any other single network company in Australia. Its regulated network:

- Is not connected to the national grid. It is a stand alone network with three separate network systems prescribed as being subject to regulation under the *Electricity Reform Act*. These are Darwin-Katherine, Alice Springs and Tennant Creek. Darwin and Katherine are combined as this system is interconnected by the Darwin-Katherine 132kV Transmission Line (DKTL);
- Has around 8,664 kilometres of regulated lines, of which the largest system, Darwin/Katherine, accounts for around 7,200 kilometres of line; and
- Operates in diverse climates, each of which brings with it unique challenges such as cyclones, over 22,000 lightning strikes a year, tropical storms with winds in excess of 100 kilometres per hour in the north, and dust storms and drought in Central Australia.

Power and Water's regulated network is summarised by voltage and type in Table 2.

Table 2 - Power and Water's Network Assets

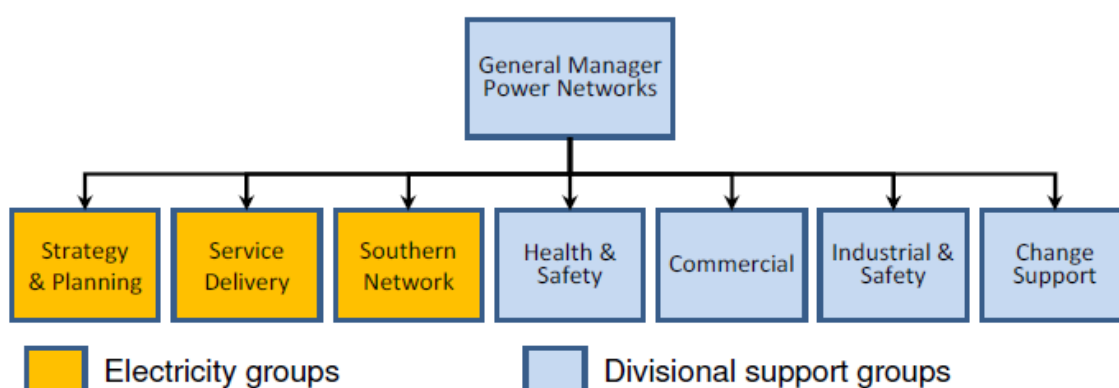
Regulated Line Lengths (km) as at 30 June 2013	
132kV Overhead	351
66kV Overhead	393
66kV Underground	38
22kV Overhead	2,834
22kV Underground	66
11kV Overhead	353
11kV Underground (includes 6.3kV)	662
SWER Overhead	9
LV Overhead	1,152
LV Underground	624
Service Overhead	566
Service Underground	871
Streetlight Overhead	63
Streetlight Underground	682
Total	8,664

2.2 Organisational overview

Power Networks is a ring-fenced electricity distribution business within Power and Water, performing the role of the Network Operator, as defined in the *Electricity Networks (Third Party Access) Act*.

The organisational structure of the Power Networks business unit is presented in Figure 2.

Figure 2 - Power Networks organisational structure



Power Networks has separated its responsibilities into two major streams. Planning and engineering activities are undertaken by the Strategy and Planning Group and delivery activities are undertaken by the Service Delivery Group. The Southern Network Group undertakes both planning and engineering activities (Strategy and Planning), and delivery (Service Delivery) activities to the Alice Springs network.

The main business sections and activities undertaken by the Strategy and Planning Group are:

- Asset Management (asset owner): comprising Asset Strategy (maintenance and upgrade strategies and programs, and asset condition), Asset Quality and Systems (Quality - standards, design guidelines, technical specifications, inventory, essential spares, asset disposal, and stock take; and Systems – Geographical Information System & Asset Management System) and Protection, Controls and Communications (protection system maintenance and upgrade strategies, and SCADA and Communication System maintenance and upgrade strategies);
- Network Engineering: responsible for the planning, design and management of network extensions, customer connections and network augmentations;
- Network Planning and Development: responsible for medium and long term distribution and transmission network development and planning, as well as providing short term operational planning support; and
- Contracts and Projects: responsible for procuring, managing and administering panel/period contracts for Power Networks and the project management of Power Networks' major, and some highly specialised minor, capital projects.

The main business sections and activities undertaken by the Service Delivery Group are:

- Field Services: responsible for emergency response capability for the transmission and distribution network, for completing Power Networks' maintenance and operating programs; and for assisting with Power Networks' capital expenditure program;
- Substation Services: responsible for assessing, maintaining and repairing key strategic substation plant and equipment;
- Test and Protection: responsible for the provision of high level pre-commissioning testing, high voltage acceptance testing of new and repaired plant, protection and power transformer preventative maintenance, as well as corrective maintenance and specific replacement projects associated with these assets; and
- SCADA and Communications: provides two distinct services – Supervisory Control and Data Acquisition (SCADA) services (SCADA group) and operational telecommunications services (Communications group). The SCADA group is responsible for the design, maintenance and support of the Alstom Energy

Management System (EMS); and the remote equipment which is monitored and controlled by the EMS. The Communications group provides design, installation, maintenance and support for operational communications systems.

2.3 Governance

Following both external and internal reviews of its capital and operating programs and processes, Power and Water has developed and implemented the Capital Investment and Delivery Framework (Framework). The Framework outlines Power and Water's corporate intent, governance processes, systems and tools available to those planning and delivering projects so that value for money is achieved through prudent investment and efficient and effective delivery. A copy of the Framework has been provided at Attachment 19.

All Power Networks' projects and works remain subject to:

- Specific detailed review, at the planning phase, of all relevant factors including actual and forecast load growth, plant condition, relative priority and resource availability;
- Internal and external approvals, including Board approval where applicable, and agreement by Power and Water's Shareholding Minister as part of the SCI process;
- The Commission as part of the Networks Price Determination process; and
- Review against the requirements of the National Electricity Rules (Capital Expenditure Objectives and Criteria).

The use of Business Case gateways under the Framework is the central mechanism by which Power and Water ensures that each investment is prudent and that the resulting projects are planned and developed sufficiently to be delivered efficiently and effectively.

Table 3 gives a summary of Business Case gateways and how they are applied. The table outlines the purpose of each gate, when in the project cycle each gate is required, what gates apply to what class of project and a target cost accuracy required to pass through each gate.

Table 3 – Business Case gateways

GATEWAY	PURPOSE	TIMING	PROJECT TYPE	TYPICAL ELEMENTS	TARGET COST ACCURACY ²
BNI – Business Need Identification	To demonstrate the need to invest and the supporting logic	During the Investment Planning Phase	All Projects and Programs ³	<ul style="list-style-type: none"> • Priority Score • Base cost estimate • Clear investment logic • Quantitative measures of success • Primary Investment Driver • Key milestones 	+/-35%
PBC – Preliminary Business Case	To demonstrate a robust development, analysis and selection of options	During the Project Development Phase	A, B	<ul style="list-style-type: none"> • Suite of option • Full options analysis (cost and non-cost) • Project Risk register • Draft Management Plans • Scope and requirements definition for preferred option • 50% design complete 	+/- 20%
BC – Business Case	To demonstrate that sufficient project development prior to going to market	End of Project Development Phase	A, B ⁴ , C	<ul style="list-style-type: none"> • Complete Management Plans • Procurement / Delivery Strategy • Detailed cost estimate • Detailed schedule • 75% design complete 	+/- 10%
FBC – Final Business Case	To ensure VFM has been achieved through the market engagement process	End of Commitment Phase	A, B ⁴	<ul style="list-style-type: none"> • Procurement recommendation • Updated cost estimate • 100% design complete 	+/- 5%
OE – Over expenditure	To govern any expenditure (or proposed) over that approved	During Delivery Phase	All Projects and Programs ⁵	<ul style="list-style-type: none"> • Quantification and reasons for cost over-run • Substitution recommendation 	n/a
PIR – Post Implementation Review	Demonstrate that benefits have been delivered through the investment and to inform continual improvement	After completion of the Delivery Phase	A and Programs, B&C if and OE occurred	<ul style="list-style-type: none"> • Confirm delivery a benefits • Project performance summary • Improvement recommendations 	n/a

2.4 Asset management

In September and October 2008, a number of electrical equipment failures at Casuarina Zone Substation resulted in widespread power disruption to Darwin's northern suburbs. Consequently, the Northern Territory Government established an independent inquiry headed by Mervyn Davies to investigate these events as well as Power and Water Corporation's operational response and electrical substation maintenance practices in Darwin. This inquiry made a number of recommendations focused on improving network asset management outcomes.

These recommendations have now largely been implemented.

Following the Casuarina substation failure, Power Networks carried out a comprehensive Remedial Asset Maintenance Program (RAMP), with the objectives of:

- Identifying the condition of the electrical assets, through testing and inspection;
- Instituting operational measures to mitigate any safety risk to personnel and the public, and the loss of electrical supply;
- Prioritising the replacement or remediation of those electrical assets found to be in poor condition; and
- Carrying out the replacement and remediation works.

The Casuarina Zone Substation incident has also acted as the trigger for a thorough review of Power Networks' asset management practices and a culture change throughout the organisation, adopted by personnel of all levels.

Power Networks now maintains its assets based on the principle of objective need. This represents a key change in Power Networks' operating environment, which will help ensure the business is able to satisfy its statutory obligations under the *Electricity Networks (Third Party Access) Act* to provide a network service to end users.

The full effect of these changes in asset maintenance practices required to maintain the assets until end of life will not be seen for some time. Accordingly progressive improvement in system performance levels will only become apparent after several years.

2.5 Strategic initiatives and programs

The strategic initiatives that Power Networks will focus on during the 2014-19 regulatory control period align with the Key Result Areas (KRAs) in the Statement of Corporate Intent 2013/14. Some of these KRAs and corresponding initiatives are described below.

2.5.1 Financial sustainability

Power Networks has undertaken a major review of its tariff structures as part of the 2014 Networks Price Determination process. The structure of the Power Networks' tariffs hasn't changed since it was first introduced in 2000. It is an overly complex tariff structure that is out of step with current industry practice and is no longer cost reflective. The restructure has been undertaken with the following high level objectives in mind:

- Enhancing cost reflectivity and reducing cross subsidies through network tariffs;
- Development of tariffs that better reflect the network's cost drivers and are more simple to administer;

- Curtailing peak demand growth and thereby, network costs;
- Improving demand side participation and energy efficiency; and
- Rolling out smart meters and time based pricing, to reduce demand during peak periods.

Power Networks has developed a new capital contributions policy to apply to network users seeking augmentation or extension of the network, and where the cost of these assets (including design, construction, installation and commissioning) cannot be fully recovered by Power Networks through future tariff revenue, a contribution will be levied. The charges under the current capital contributions framework are not cost reflective.

The objectives of the new Networks Capital Contributions Policy are:

- To provide appropriate economic pricing signals to network users that reflect the true cost of connection to Power and Water's electricity networks or any new or upgraded network access services;
- To ensure the commercial viability of connections made to Power and Water's electricity networks, in order to provide a return to shareholders commensurate with the required investment; and
- To ensure more equitable outcomes for both new and existing network users.

2.5.2 In good operational and asset health

The implementation of the ESRI and Maximo integrated asset management system is a catalyst to rapidly improve asset management and maintenance practices across Power and Water. Considerable effort has been employed to define asset classes, and to determine and produce works management process flows. The introduction of the new systems provides opportunities to improve the management of assets, particularly in the areas of asset planning, maintenance planning and condition monitoring. Works will continue to exploit the full potential of the system.

The new asset management system will facilitate the development of detailed asset management plans for each asset class within Power Networks. The current maintenance strategies will be maintained or modified in light of information from the Industry Working Group and condition information obtained during preventative and corrective maintenance. The plans will focus on improving the safety, reliability and operability of assets in order to provide the best possible customer supply reliability outcome within regulatory reliability targets.

As maintenance is completed asset condition information is captured by the new asset management system in two ways. Firstly, measurements made during preventative maintenance are entered into the system as metered values that are held against the asset. Secondly, during corrective maintenance the "Part, Failure and Cause" is captured through a structured hierarchy that is unique to each asset class or model. Both condition and failure data, along with information from the Industry Working Group and Power Network maintainer forums, is analysed as a routine component of the maintenance cycle. This information forms the basis for

decisions regarding changes in maintenance practice or asset replacement justification.

Targeted feeder upgrades have been defined by analysing outage information to identify poorly performing feeders using the System Average Interruption Duration Index (SAIDI) and Standards of Service (SOS) measures. Outage information currently contains the asset, cause, protection that operated and the percentage of feeder affected, which are all considered, along with level of the completion and effectiveness of past upgrades, in determining what further measures should be employed to improve the performance of individual feeders. The asset condition knowledge held by maintainers is also exploited as the suggested improvements are reviewed and finalised with the relevant work teams.

The asset team initiative, introduced by Power Networks in 2011/12, will continue through the 2014-19 regulatory control period. This initiative gives Defective Asset Reports (DARs) increased attention with reporting now being collated by the maintainer group within Service Delivery. Asset teams, comprised of representatives from Asset Management and the maintainer groups, scrutinise the defects to ensure they are correctly prioritised and the maintainer group has the resources to address the defects.

Power Networks has begun to scope a project to implement an Integrated Distribution Management System (IDMS). An IDMS has the potential to improve system reliability and provide a powerful tool for better managing faults and outages. The IDMS is scheduled to be implemented by the end of the first year of the regulatory control period.

McMinns Zone Substation, City Zone Substation, Berrimah Zone Substation and Casuarina Zone Substation 66kV Outdoor Switchyard are all approaching end of life. Assets at these sites pose a considerable risk to Power Networks that is being carefully managed. Regular reviews of DARs at sites approaching end of life are conducted to ensure maintenance and repair activities adequately reduce the risk of failure. The implementation of the Early Contractor Involvement (ECI) contract will deliver this substantial asset replacement program in zone substations identified above within the desired period.

Other asset populations that have been targeted for replacement include oil ring main units, high voltage cables, SCADA and communication systems, and switching station oil circuit breakers.

2.5.3 Organisationally capable

Over the course of this regulatory control period much has been achieved in transforming Power Networks into a capable and results focused business. This started with the structural changes as recommended by the PricewaterhouseCoopers review in 2008, moving to an 'Asset Owner', 'Service Delivery' model with clearly defined roles and responsibilities. The implementation of the findings and recommendations of the Mervyn Davies Review strengthened the asset management and planning functions as well as introducing a condition based preventative

maintenance regime. This meant the introduction of new test equipment, new processes and an up-skilling of maintainers. A small internal training group was established and a training centre built.

The next regulatory control period is a time to consolidate and improve in works scheduling, planning and efficient delivery. The implementation of the new asset management system provides an opportunity for better analysis of work productivity, asset condition and asset performance measurement. All this will be necessary to provide the increased level of analysis and justification that will be required if Power Networks comes under the Australian Energy Regulator (AER).

2.5.4 Environmentally sustainable

Power and Water continues a commitment to reducing its impact on the environment. Power Networks will contribute to this effort by:

- Identifying potential areas to reduce its environmental footprint such as changing to an improved environmental design for new zone substation transformer oil separation pits;
- Fully complying with environmental management plans established for major projects; and to
- Annually reviewing and updating Power Networks' environmental risk register.

2.5.5 Contributing to regulatory environment development

The Commission indicated in its Framework and Approach Decision Paper that it will seek to align electricity industry regulatory arrangements with those of the NEM where possible⁵. Power Networks supports this change in principle, wherever the NEM arrangements can efficiently be applied within the Territory.

There are very significant differences in both the scale and scope of Power Networks' operations to the existing NEM businesses and there are aspects of the NEM and Rules framework that:

- Cannot be applied at this time;
- In some cases, cannot be economically applied; or
- Are inappropriate for the Northern Territory circumstances.

Notwithstanding these caveats, Power Networks will continue to work with the Commission in a constructive manner to contribute to efficient and effective regulatory development.

⁵ 2014-2019 Network Price Determination Framework and Approach Decision Paper, November 2012, p. 10.

2.5.6 Improved engagement with the wider community

Power Networks will continue a robust public consultation process where the construction of major infrastructure may impact the public. This will be particularly required for the construction of the Archer to Palmerston 66kV transmission line, which may traverse close to residential suburbs.

During the 2014-19 regulatory control period Power Networks intends to develop other consultation processes with stakeholders and customers. The Demand Management Procedure envisages the establishment of a reference group of providers of demand management and non-network alternatives to network augmentation, which will assist Power Networks in developing such alternatives to network reinforcement where they are economic to do so.

Power Networks' inaugural Network Management Plan was not published publicly. However, it is anticipated that future versions of this document will be available to the public, and will inform interested persons of Power Networks' and its development plans.

The Pricing Proposal that accompanies this regulatory Proposal will also be published and will provide customers and stakeholders with the rationale that underpins Power Networks' pricing strategies and the development of more cost reflective tariffs.

2.6 Strategic and operational risks

2.6.1 Capital investment program delivery

Over the forthcoming regulatory control period Power Networks still has a significant capital program to deliver. To mitigate the risk of failing to deliver this program Power Networks has:

- Placed the Contracts and Projects section in Strategy and Planning to embed project managers in the planning process for individual projects, mitigating the risk of a disconnect between planning, internal project approvals and actual delivery;
- Recruited additional internal project and technical staff (as recommended by Huegin Consulting⁶) and expanded the use of contractors/consultants to cater for increasing work programs;
- Implemented an alternate contracting methodology (Early Contractor Involvement) for delivery of Zone Substation Asset Replacement program to expedite the design and delivery of approved projects;
- Standardised zone substation designs to minimise design and delivery timeframes and costs; and

⁶ Due to the increased capital works program resulting from the Davies Review recommendations for Power Networks, Power and Water engaged Huegin Consulting in 2010 to determine the size of the workforce required to deliver the program of works and identify whether a 'gap' exists versus the current workforce.

- Established long term period contract arrangements for the supply of all high voltage switchgear, a key piece of equipment that could otherwise become a delivery bottleneck.

2.6.2 Organisational capability

The structure of Power Networks has a focus on planning capability and delivering the significant capital investment and maintenance programs.

While the current Enterprise Bargaining Agreement has resulted in Power and Water becoming a more competitive employer, in terms of salary and other benefits, this may not be sufficient to ensure the recruitment and retention of adequate numbers of skilled and experienced staff particularly with the Inpex development ramping up over the next two to five years.

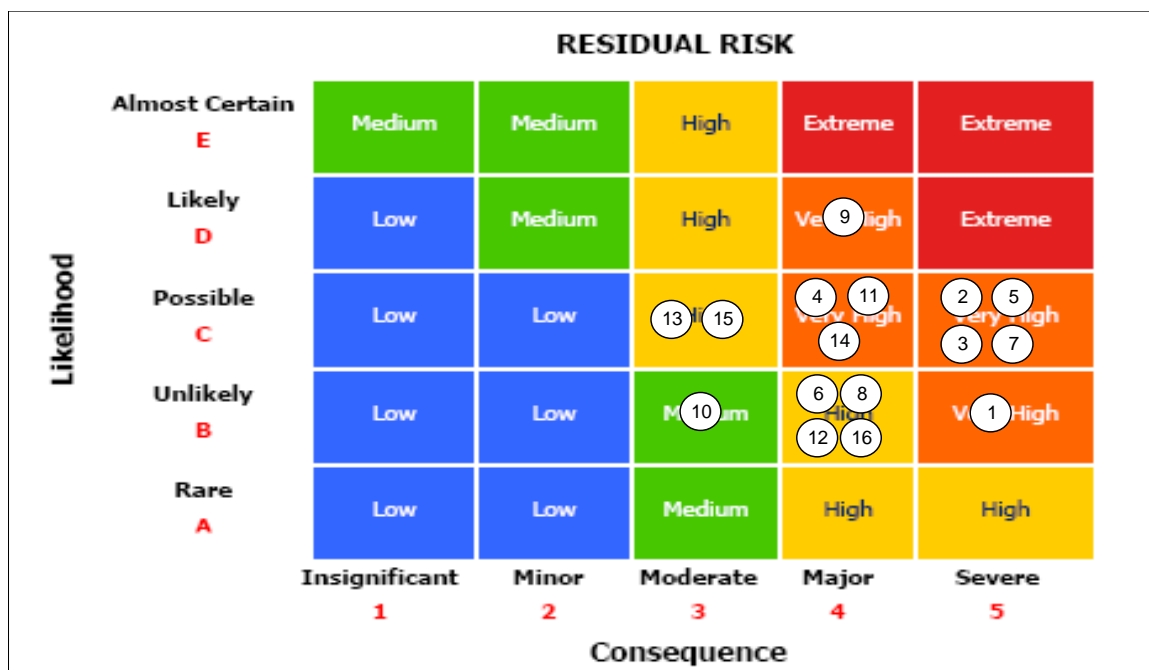
A critical risk therefore is that Power Networks may not be able to recruit and retain the necessary skills and experience required to implement the capital investment and maintenance programs.

To mitigate this risk, Power Networks is implementing strategic workforce planning initiatives including the development of succession and retention plans, focused training and development, and maximising the comparative benefits contained in the Enterprise Bargaining Agreement through targeted recruitment advertising. The continued operation of panel period contracts for specialised services also provides alternate sources of skilled resources in times of internal staff shortages.

2.6.3 Operational risks

Power Networks has increased its focus on risk management and actively uses the GRACE system to identify and manage its operational risks. The risk heat map in Figure 3 provides a snapshot of Power and Water's risk categories and residual risk profile.

Figure 3 – Operational risk assessment



The categories of risk that are considered in this assessment are set out in Table 4.

Table 4 – Categories of risk

ID	Description
C1	Crisis Management
C2	Public Safety
C3	Staff and Contractor Health & Safety
C4	Environmental
C5	Water Quality / Waste Management
C6	Fuel Supply Management
C7	Legal and Regulatory Compliance
C8	Information Technology, SCADA and Communications
C9	Project and Contract Management
C10	Terrorism, Security and Vandalism
C11	Capacity and Capability
C12	Supply of Core Services
C13	Financial Management
C14	Corporate Image and Reputation
C15	Competition
C16	Stakeholders

Of the categories that have a residual rating of very high, the following three are of the highest priority for Power Networks:

- **3. Staff and Contractor Safety** – The Corporation has implemented a range of safety training and awareness programs, designed to improve Power Networks’ safety practices and culture. These include interventions in the areas of behaviour-based safety, communication and injury management, which is supported by a code of conduct with a strong emphasis on safety. Additionally, safety professionals have been embedded within Power Networks.
- **2. Public Safety** – Comprehensive safety management processes are in place to minimise the risk of Power Networks services or infrastructure affecting a member of the public. A number of public information campaigns have been conducted to highlight the dangers associated with vegetation management and overhead power lines.
- **1. Natural Disaster** – Power Networks has emergency response and crisis management plans in place that are designed to mitigate the impact of natural disasters such as major cyclones. The experience from Cyclone Carlos in 2011, which caused widespread power outages and flooding throughout Darwin and

the rural area, confirmed Power Networks preparedness to respond to these types of event disasters.

2.7 Capability development and innovation

Power Networks strives to improve its efficiency and performance through ongoing capability development and innovation. This section outlines a number of key capability developments and innovations Power Networks has established or plan to establish over the forthcoming regulatory period.

2.7.1 Condition based asset maintenance

Over the last four years, as Power Networks has transitioned to a condition based preventative maintenance regime, maintenance staff have been trained to perform condition based maintenance utilising modern test equipment. This increased capability includes:

- Partial discharge testing of high voltage switchgear;
- Circuit breaker contact resistance and timing tests;
- Dielectric Dissipation factor testing of high voltage transformer bushings; and
- Infrared testing of network infrastructure.

2.7.2 Targeted outsourcing

Specialist testing, such as partial discharge testing of 66kV high voltage cables, is outsourced. This is due not only to its specialised nature, however also to the infrequent requirement for such testing and the high costs that would be involved in purchasing and maintaining the test equipment.

In addition, Power Networks outsources some of its maintenance and construction activities. The drivers for what is outsourced include:

- Cost and efficiency;
- Frequency of the service;
- Whether it is a core function; and
- Specialised nature.

For example, vegetation management is outsourced due to both cost and core function drivers. Some construction activities on the distribution network are outsourced as it is inefficient to maintain a workforce, along with plant and equipment, to complete this work due to the varying nature of construction activities. This is even more so in the zone substation and transmission asset classes, where nearly all design and construction activities are outsourced.

There are many other non-core areas such as onsite concrete supply, pole rehabilitation, welding, traffic management and building maintenance where it is more cost effective to contract out these activities.

In order to set up and manage this vast array of contracts, this function was centralised in Power Networks within the Contracts and Projects section in Strategy and Planning. This group is responsible for the delivery of the major projects, as well as establishing and managing most contract requirements across Power Networks.

2.7.3 New contracting models

With the introduction of a condition based approach to maintenance it became evident that, given the poor condition of assets at a number of zone substations, a significant replacement program was required. Due to the tight timeframes required, and the forecast cost to rebuild at least five zone substations, an alternative relationship basis of contracting was selected. Early Contractor Involvement (ECI) involves the contractor working with Power Networks at the early stages to identify the most cost effective solution for each zone substation site. A price is then negotiated on an 'open book' basis to design and construct each zone substation.

To date this innovative approach has led to faster construction times, projects tracking within budget and considerable less administrative burden with less contract administration (i.e. only one contract as opposed to many from a traditional based approach). Additionally, contract variations have greatly reduced as project and construction risks are identified collaboratively at the early stages. These risks are either mitigated or allocated to the contractor or Power Networks, wherever that risk can be best managed.

2.7.4 Mobile substations

As a result of the poor condition of zone substation assets, two NOMAD mobile 66/22/11 kV 10 MVA substations were purchased. Additionally, a mobile 22 or 11 kV switchboard that directly connects to a NOMAD was also purchased. This provides some capability for the loss of a transformer at a zone substation. With the introduction of the new Network Technical Code and Planning Criteria, future zone substations up to 10 MVA need only have a single transformer provided a NOMAD can be connected within 12 to 36 hours. These NOMADs also allow existing remote/rural single transformer zone substation sites to be bypassed for maintenance or asset replacement activities.

Another potential innovative use of this mobile solution is to meet supply date requirements for new mine sites or where there is sudden unplanned load growth and the NOMAD can be deployed until zone substations are either upgraded or built.

2.7.5 Interval meter rollout

During the forthcoming regulatory control period, Power Networks proposes a full rollout of interval meters to customers consuming between 40-750 MWh per year. This supports the implementation of cost reflective network pricing, and provides appropriate incentives to manage network demand growth. Power Networks also proposes to carry out a trial interval meter rollout to customers consuming between 15-40 MWh per year.

2.8 Stakeholder expectations for the 2014-19 regulatory control period

In making this regulatory Proposal, Power Networks is seeking to meet the expectations of its stakeholders in a number of ways.

The proposed forecast expenditures have been kept to a minimum and their prudence and efficiency demonstrated. This will:

- Minimise the increase in prices to Power Networks' customers; and
- Ensure that non-network and demand management solutions are developed where they are economic; whilst
- Ensure an appropriate commercial return on the electricity network business to our NT Government shareholder.

Power Networks proposes to maintain network security standards at current levels and to make gradual improvements to reliability levels throughout the 2014-19 regulatory control period. Meeting customers' expectations on reliability is an important priority, as customers need to receive a service that represents value for money.

Power Networks recognise there are some inequities in the current suite of network tariffs, which do not reflect the networks' cost structures and result in certain groups of customers paying more than their fair share of network costs. The Pricing Proposal that accompanies this regulatory Proposal explains how Power Networks proposes to develop cost reflective tariffs that are more equitable.

Where practicable, this regulatory Proposal has been developed in accordance with the Rules and the NEM regulatory frameworks. During the course of the regulatory control period, further progress towards implementing the NEM procedures will provide stakeholders with assurance that the regulatory bargain is being met in accordance with mainstream regulatory practices and standards.

3 Transitional issues

There are a range of transitional issues associated with the 2014-19 regulatory control period. The majority of these have arisen due to changes in the regulatory framework that are being implemented by the Commission.

The Commission has stated that its approach to the 2014 Network Price Determination will be to adopt:

"those parts of Chapter 6 of the NER as applied by the AER and those models and guidelines developed by the AER pursuant to the NER that are not inconsistent with the NT Access Code"⁷.

Power and Water accepts the Commission's position to adopt the approach used by the AER and to apply those parts of Chapter 6 of the Rules that are consistent with the Code. However, this should apply only where it is appropriate and where the Commission can demonstrate a net benefit from so doing.

Progression to the Rules framework

Power and Water also notes that the 2013/14 NT Budget proposed a transfer of certain electricity market functions from the Commission to the Australian Energy Regulator (AER) from July 2014.⁸

Power and Water considers that full adoption of Chapter 6 of the NER and the AER processes will not be possible and variations or transitional approaches may be required, for the following reasons:

- The small size of the market and high scale costs in the Northern Territory as compared to other systems in the NEM means that some aspects of the Rules and AER's regulatory approach may not be cost effective in the Northern Territory either at this time or possibly ever, particularly when it is considered that the Northern Territory electrical energy consumption represents less than 1 per cent of the NEM total;
- Increased documentation, data provision and reporting requirements, and limited resources available (internally and externally) to Power and Water and the Commission mean that some aspects of the Rules and the AER's approach will be difficult to comply within the required timeframes. In this context, it is pointed out that the NEM Distribution Network Service Providers (DNSPs) supply from 2 to 16 times the energy consumption of Power Networks, have significantly greater resources at their disposal and have adapted to the NEM since its inception in 1998; and
- The differences in the market structure and regulatory environment in the Northern Territory compared to the NEM means that some aspects of the

⁷ Utilities Commission, 2014-2019 Network Price Determination Framework and Approach Decision Paper, November 2012, p.28.

⁸ 2013-14 NT Budget, Budget Paper No. 3 - Agency Budget Statements, p.103.

Rules and AER's approach will need to be modified for the NT's circumstances.

While accepting that Power Networks may not be able to comply with some aspects of the Rules framework, the Commission has stated:

"... the Commission expects a more substantial case to be made where PWC (or other stakeholders) consider that application of the NER should be delayed or not applied. Generalised assertions are not sufficient and should be substantiated by reference to cases, costs or data on the likely impacts on the business and the short and long impact on customers."⁹

Power Networks' firm view is that good regulatory practice makes it incumbent upon the Commission to demonstrate there is a positive net benefit from the regulatory changes it proposes, rather than assuming that the NEM framework and AER reporting is best practice or appropriate and placing the onus on Power Networks and stakeholders to demonstrate otherwise.

3.1 Regulatory Information Notice requirements

The regulatory information requirements set out in the Commission's RIN are largely those which have been developed by the AER for its NEM distribution businesses. These requirements continue to evolve with development of the Rules framework, including the changes that followed the Distribution Planning and Expansion and the Economic Regulation of Network Service Providers Rule changes^{10,11}.

The Commission has adopted a staged approach to the provision of information specified in the RIN, each stage of which has involved extensive documentation as well as the completion of spreadsheet templates. The information required of Power Networks has been much greater in volume and complexity than that required at the previous regulatory determinations. This Proposal is the sixth and final stage in the process and brings together and, where necessary, updates to the information supplied in earlier stages.

Annual regulatory reporting requirements

Power Networks anticipates that significantly increased reporting requirements will accompany the transition to the AER-based regulatory reporting framework. The annual reporting requirements for the NEM based DNSPs are much more onerous than Power Networks' current regulatory reporting obligations and will require annual updating of the RIN templates to accompany the regulatory accounts. This will require changes to systems and processes that will take place progressively.

⁹ Ibid, p. 27.

¹⁰ AEMC, Rule Determination - National Electricity Amendment (Distribution Network Planning and Expansion Framework) Rule 2012, 11 October 2012.

¹¹ AEMC, Final Position Paper - National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, 15 November 2012.

Power and Water expectation is that the Commission does not make changes to the regulatory reporting arrangements without consultation, as the consequences for Power Networks' systems, processes and resourcing can be far reaching and costly.

Service Target Performance Incentive and Efficiency Benefits Sharing Schemes

Whilst the Commission has not fully implemented the AER's suite of regulatory incentives it has adopted some aspects, for example the implementation of GSL arrangements that require additional resources. Power Networks is concerned that the Commission may proceed with other aspects of the AER's incentive schemes during the forthcoming regulatory control period, and notes that costs associated with these schemes has not been captured in the 2014 Networks Price Determination.

3.2 Network Technical Code and Network Planning Criteria

Power and Water submitted a revised version of the existing Network Connection Technical Code and Network Planning Criteria to the Commission for review in March 2013.

Network Technical Code

The revised Network Technical Code (NTC) is an update of the existing Code, to improve alignment with and incorporate changes that have been adopted both in the NEM and in Western Australia. Specific issues that have been addressed in the revised NTC include updates to supply quality standards and the technical requirements for small embedded generators such as solar PV, to ensure such installations do not jeopardise the security and reliability of supply to Network Users.

These documents form Attachment 2 and Attachment 3 to this Proposal. The Proposal assumes the NTC will be approved. Whilst the forecast capex and opex expenditures that form part of this Proposal are based upon the revised NTC this has not resulted in a material change to those expenditures.

Network Planning Criteria

Power Networks has also revised the Network Planning Criteria (NPC). The NPC have been combined into a single document with the NTC at Attachment 3, because of their close relationship and to avoid overlap.

The existing network design philosophy (based on the provision of 'n-1' or 'n' levels of network contingency) has been expanded to provide a comprehensive set of supply contingency criteria. These criteria will underpin the future development of the transmission and distribution networks.

Importantly, the new supply contingency criteria do not specify the network configuration. Rather, they have been broadened to specify the planned recovery time, in situations varying from remote rural supply to the Darwin CBD. A supply contingency in a particular area may include the unplanned failure of a local or

embedded generator, or an element of the network. Meeting the planned recovery time may involve the deployment of local or embedded generation, strategic spares, enhanced operational response, management of demand or augmentation of the network. This performance-based format encapsulates existing practices and permits greater scope for non-network alternatives and operating solutions.

This Proposal assumes the NPC will be approved by the Commission. The capital and operating expenditure forecasts that constitute part of this Proposal assume the requirements of the NPC. The adoption of the NPC has made some minor differences in the timing of some augmentations, leading to a small overall reduction in capital expenditure.

3.3 Network Capital Contributions Policy

Power and Water has developed a new Network Capital Contributions Policy (NCCP), to replace the current Distribution System Expansion Policy (for small customers and developers) and the Capital Contributions Policy with a single document. This was submitted to the Commission in March 2013. An outline of the changes that have been made, the reasons for making them and their implications is provided in section 8.13 of this Proposal.

Power Networks has assumed that the Commission will approve the new NCCP. This will result in a small increase in both contributed assets and cash contributions through the application of more cost reflective arrangements. This will offset costs that would have otherwise been apportioned to existing customers. The new NCCP has been assumed in the revised forecast of capital contributions in this Proposal.

3.4 Regulatory modelling

The following transitional issues relate to the revenue and price modelling associated with this Proposal, and also apply to subsequent reporting throughout the 2014-19 regulatory control period.

Revenue modelling

The Commission has agreed that a pre-tax framework will be used for regulatory modelling in the 2014 determination. The main implications of this are:

- The AER's Roll Forward Model (RFM) is used to determine the opening asset base on 1 July 2014. This model has not been altered, although the tax asset base calculation is not used;
- The Commission has developed a modified version of the AER's Post Tax Revenue Model (PTRM). This has been termed the NT Revenue Model (NTRM). The alterations to the model convert to a pre-tax framework by removing the tax calculation from the building block calculation and changing to a pre-tax Weighted Average Cost of Capital ($WACC_{Pre\ tax}$).

Regulatory Asset Base

Power Networks will maintain a RAB separate to the Financial Asset Register during the 2014-19 regulatory control period, due to differences in depreciation and in recognising capital expenditure as incurred, as opposed to capitalising with Works in Progress (WIP) on project completion. This separate RAB will be maintained in a manner consistent with the RFM.

Taxation Asset Base

Whilst the pre tax framework used for the 2014 revenue determination does not require a tax asset base to be maintained, the Commission has stated:

"The Commission expects that PWC's regulatory proposal will include a project plan and timeframes to transition to a post-tax asset base for the regulated networks business well in advance of the 2019 determination process."¹²

Power Networks must develop and maintain a Network Tax Asset Base (TAB) separate to the Corporate taxation records, to enable the full implementation of the AER's Post Tax Revenue Model at the start of the next regulatory control period. Power Networks proposes the following stages in this process:

- Development of initial Network TAB (as at 30 June 2015): 30 Sept 2015
- Review of network TAB, reconciliation with Corporate taxation and report to Commission: 30 Sept 2016
- Incorporation of TAB into revenue modelling: 30 Sept 2017

3.5 Network cost pass through

The Commission's Final Determination on the Networks Cost Pass Through (May 2013) is that Power Networks should recover the approved cost pass through amount in two stages:

- \$25 million in the 2013/14 regulatory year; and
- the remaining \$29.92 million (\$2012/13) will be carried over to the next regulatory control period commencing 1 July 2014.

The Commission determined that the manner in which the remaining amount of \$29.92 million is recovered over the 2014-19 regulatory control period will be determined as part of the 2014 Network Price Determination process¹³.

Power and Water considers the most convenient way of permitting this sum to be recovered is to use the established provision in the NTRM. The amount will then be

¹² 2014-2019 Network Price Determination Framework and Approach Decision Paper, November 2012, p. 57.

¹³ Utilities Commission, Cost Pass Through Application, Final Determination, May 2013, p.5

included in the building blocks determination made by the Commission and incorporated into the revenue cap form of price control in 2014/15.

3.6 Pricing Proposal

Distributors in the NEM jurisdictions are required to lodge a detailed Pricing Proposal each year. The pricing Proposals required under the NER are much more onerous than current pricing Proposal requirements. Power Networks will need to develop its modelling and reporting systems to comply with additional reporting obligations.

Transition from a Price Cap to a Revenue Cap

The transition from a price cap to a revenue cap form of price control will result in changed modelling and reporting requirements. Whilst Power Networks believes the requirements of the revenue cap will be more straightforward, particularly in relation to the introduction of new tariffs and the transfer of customers between tariffs, a different form of price modelling will need to be developed, accommodating forecast tariff component growth to determine target revenues.

3.7 Network Management Plan

Power Networks produced its inaugural Network Management Plan in December 2012. Concurrently, progress towards the development of uniform distribution network reporting arrangements took place in the NEM, with the Distribution Network Planning and Expansion Framework Rule changes. The NEM requirements for the Distribution Annual Planning Report (DAPR) would impose significant additional obligations, with which Power Networks will not initially be able to comply.

Investment processes

The Commission has decided that the Regulatory Test is not appropriate for Territory circumstances. Power Networks agrees with this decision¹⁴. Power Networks accepts that some aspects of the RIT-D process, in particular consultation associated with developing non-network options, are adaptable to the Territory's circumstances. This will have an impact on the resources required to plan the network.

¹⁴ 2014-2019 Network Price Determination Framework and Approach Decision Paper, November 2012, p. 64.

4 Classification of services

Power Networks sets out the proposed classification of its network services in this chapter of the Proposal. This classification is substantially the same as that which applied during the 2009-14 regulatory control period and reaffirmed by the Commission in its Framework and Approach Decision Paper¹⁵. The reasons for differences are explained in this chapter.

In relation to the Rule requirements concerning Negotiated Services and the requirement for a Negotiating Framework, the Commission has confirmed that the Code does not authorise compliance with Part D of the Rules and this requirement will not apply.

As required by section 6.8.2(c)(1) of the Rules, this Proposal includes a Classification of Services Proposal in Attachment 4, showing how Power Networks believes the distribution services should be classified and the differences from the classification in the Commission's Framework and Approach Decision Paper.

Code and Rule requirements

Section 72 of the NT Electricity Networks (Third Party Access) Code (Code) sets out the provisions concerning exclusions from the network revenue or price cap. The Commission has determined:

- Services which are subject to effective competition, in accordance with clause 72(2); and
- A range of network services that do not lend themselves to being regulated by the price control mechanism as excluded services, in accordance with clause 72(3).

Part B, clause 6.2 of the Rules permits the Regulator to classify the services provided by a distributor into Direct Control Services (subdivided into Standard Control and Alternative Control Services) and Negotiated Services. Those services that are not so classified are not regulated.

¹⁵ Utilities Commission, 2014-2019 Network Price Determination Framework and Approach Decision Paper, November 2012, p. 40.

4.1 Framework and Approach Decision

In 2009 the Commission re-expressed its determination of excluded services under the Code in the terminology of the service classification used in the Rules. Power Networks submitted a Service Classification Proposal to the Commission with regard to the requirements of clause 6.2 of the Rules, which was accepted by the Commission. An overview of that classification of services is shown in Table 5.

Table 5 – Classification of services (overview)

Service provided (Rules terminology)	Description	Service Level	Form of regulation and pricing
Standard Control Service	Network services	Supply of services at mandated standards	Regulated - recovered through network tariffs
	Connection services		
	Metering services		
Alternative Control Service	Network services	Supply of services at above standard or non standard levels	No price control - recovered as fee based services or as quoted services, depending on the nature of the service provided
	Connection services		
	Metering services		
	Miscellaneous network related services	Supply of miscellaneous services	
Negotiated Services	No services fall into this category		N/A
Unclassified Services	Non-network services	As agreed	Not regulated

The Commission has determined that no change is necessary and in the 2014-19 regulatory control period will continue with the service classifications that it adopted in 2009¹⁶.

The Commission has also indicated that it will not approve prices relating to alternative control services.

4.2 Power Networks' proposed classification of distribution services

Power Networks' Classification of Services Proposal is included as Attachment 4 to this Proposal. The proposed classification of services elaborates on the description of services to be provided and largely follows the same classifications as those set out in the Commission's Framework and Approach Decision Paper¹⁷.

¹⁶ Utilities Commission, 2014-2019 Network Price Determination Framework and Approach Decision Paper, November 2012, p. 43.

¹⁷ Utilities Commission, 2014-2019 Network Price Determination Framework and Approach Decision Paper, November 2012, p. 40.

The points of difference between the Commission's proposed classification of services and those proposed by Power Networks arise for two reasons:

- Additional services that did not form part of the Commission's classification of services; and
- Changes to some fee-based alternative control services that are proposed to be reclassified as quoted alternative control services.

These proposed changes and the reason for them are described in the following sections.

4.2.1 Standard control services

Standard control services and their definition are proposed to remain unchanged for the 2014-19 regulatory control period. As shown in Table 5, this classification includes the provision of network, connection and metering services at mandated standards.

4.2.2 Alternative control services

Alternative control services and their definition are also proposed to remain largely unchanged for the 2014-19 regulatory control period. As shown in Table 5, this classification includes the provision of network, connection and metering services at above standard or non standard levels, plus a range of miscellaneous network-related services.

Power Networks proposes the following changes to the existing alternative control services arrangements. These changes are to introduce some new services where Power Networks can economically provide them, and improve the cost reflectivity of the existing arrangements.

Additional alternative control services

Quoted Service: Investigation and testing services

Power Networks has a range of specialised test equipment and trained staff, to carry out the maintenance of its network assets. It is proposed that this test equipment and staff could be made available as a service to customers to rent or for in-house electrical testing and investigation, as required by customers. Such specialised testing equipment and services would otherwise need to be obtained from interstate by the customers concerned.

Test equipment and/or personnel would be made available for rental as a Quoted Service only if available, and on the basis that it would not jeopardise the supply of standard control services.

Quoted Service: Provision of non-standard street light assets

Increasingly, street light customers are seeking the provision of non-standard luminaires and fittings (eg. LED or other high efficiency designs, or decorative luminaires).

This Quoted Service will enable Power Networks to provide luminaires and fittings of the customer's choice, subject to Power Networks' approval with regard to maintainability.

Fee based service: Provision of network capacity in excess of Network Technical Code requirements

Power Networks proposes a fee-based alternative control service for the provision of network capacity in excess of the levels required by the revised NTC, to larger commercial customers with suitable meters.

The NTC specifies the minimum power factor at a network user's connection shown in Table 6.

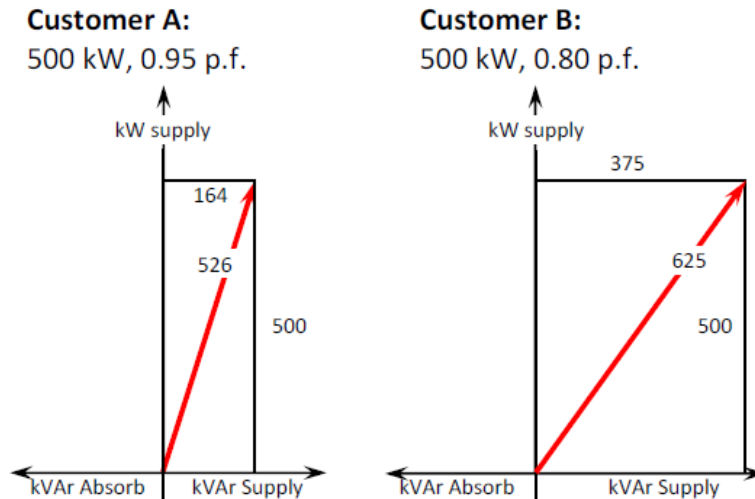
Table 6 – Network User power factor requirements

Supply Voltage (nominal)	Permissible Power factor Range
132 kV / 66 kV <66 kV	0.95 lagging to unity 0.9 lagging to 0.9 leading

A significant proportion of business customers have power factors lower than these permissible levels. Those customers that have low power factor place a greater demand on the network, which imposes additional costs on all customers through the need to augment network capacity, to provide reactive power compensation (capacitor installations), and additional network losses.

The additional network capacity used by a customer with low power factor is illustrated in Figure 4. The two customers A and B each have the same active power demand of 500 kW, but different reactive power demands.

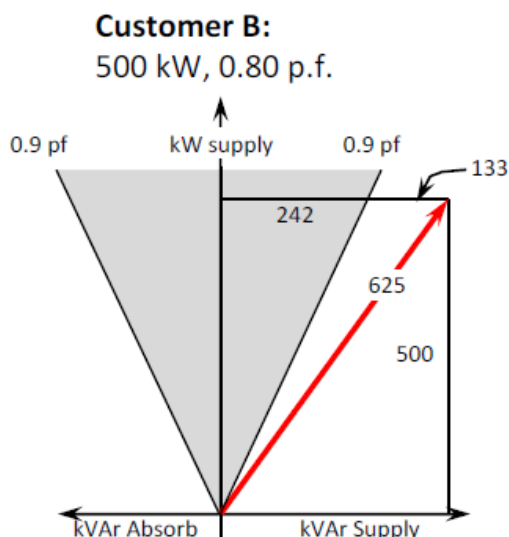
Figure 4 – Power factor and demand on the network



Customer A has a power factor of 0.95 and is compliant with the NTC. Customer B, on the other hand, with a power factor of 0.8, is non compliant.

The permissible power factor is shown in Figure 5. In this diagram, the shaded area represents the power factor permitted by the NTC.

Figure 5 – Permissible power factor in the Network Technical Code



The reactive power demand of Customer B exceeds the NTC limitation by 133 kVAr. This is the excess reactive power (termed "Excess kVAr") consumed by the customer.

Power Networks proposes to implement an Excess kVAr charge during the 2014-19 regulatory control period, to improve customer compliance with the NTC requirements, as a Fee-based Service.

It should be noted that SA Power Networks implemented such a charge in 2007 and has very successfully improved the power factor compliance of its business customers.

Changes from fee-based to quoted alternative control services

Quoted Service: Wasted attendance

The diverse nature of Power Networks' territory is such that there can be a great disparity in the length of time to travel to and from customers' premises. The former fee-based charge for this service did not recognise this disparity, nor the type of vehicle or number of staff involved. It is proposed that the cost of wasted attendance will be recovered on the basis of the actual time and resources incurred as a Quoted Service.

Quoted Service: Asset location and identification services

There can be a great variation in the time taken to travel to site and in the actual task of locating services, which depends upon the site conditions and the route length to be identified.

It is proposed that the cost of asset location and identification will be recovered on the basis of the estimated time and resources incurred as a Quoted Service.

Quoted service: Temporary Supply

At present, low voltage temporary supplies are subject to a fee and high voltage temporary supplies are subject to quotation.

The diversity in arrangements for low voltage temporary supplies means there is a significant variation in cost and thus a fixed fee is not appropriate. It is proposed that all temporary supplies would be treated as Quoted Services.

5 Control mechanism for standard control services

The control mechanism for standard control services is used to establish a revenue or price path for each of the years between regulatory determinations. Power Networks' prices are subject to a Weighted Average Price Cap (WAPC) in the 2009-14 regulatory control period.

5.1 Framework and Approach Decision

Power and Water submitted to the Commission that a change from a WAPC to a revenue cap in the 2014-19 regulatory control period is preferred, principally because it would reduce the revenue risk associated with the WAPC in an environment of uncertain growth and sales outcomes. This was in line with the preference that the AER has indicated for a revenue cap in New South Wales and the Australian Capital Territory¹⁸.

The Commission has decided to apply a revenue cap form of control mechanism for standard control services during the 2014-19 regulatory control period, subject to the following provisions¹⁹:

Code and Rule requirements

The Code and Rule requirements in respect of the control mechanism for standard control services have the same intent:

- Clause 70(2) of the Code requires the regulator to apply a revenue or price cap to adjust the revenue or prices by increasing the previous year's cap in to reflect real network cost drivers and CPI and decreasing it by an efficiency gains factor ("X factor").
- Clause 6.2.6(a) of the Rules states: "For *standard control services*, the control mechanism must be of the prospective CPI minus X form, or some incentive-based variant of the prospective CPI minus X form ..."

With regard to the form of the control mechanism (eg. revenue cap, price cap or other formulation) for the second and subsequent regulatory control periods, the Code requires the regulator to consider the price regulation objectives in clause 63.

The Rules provide for consultation in determining the form of the control mechanism in the Framework and Approach paper, in clause 6.8.1(b)(1)(i). This is the general approach that has been followed by the Commission.

"6.81 Any variation between the maximum allowable revenue (MAR), as determined by the Commission, and the actual revenue collected by the network service provider is to be monitored in the under's and over's account. PWC must provide information on this account to the Commission as part of their annual pricing proposals.

6.82 If the under/over recoveries compared to the MAR for year t are:

- less than 2 per cent, the under/over recovery will be cleared within one regulatory year

¹⁸ Discussion Paper - Matters relevant to the framework and approach, ACT and NSW DNSPs 2014–2019 - Control mechanisms for standard control electricity distribution services in the ACT and NSW, April 2012.

¹⁹ Utilities Commission, 2014-2019 Network Price Determination Framework and Approach Decision Paper, November 2012, p. 54.

- between 2 per cent and 5 per cent, the under/over recovery can be spread over two regulatory years
 - greater than 5 per cent, PWC must submit a plan to the Commission detailing how it proposes to clear the balance of the under's and over's account.
- 6.83 A notional interest charge, or an interest credit as appropriate, will be applied on the cumulative balance at the end of each financial year.
- 6.84 A side constraint will also be applied such that the weighted average price for each individual end-use customer for a particular year of the regulatory control period is not to exceed the corresponding weighted average price for that individual end-use customer for the preceding regulatory year by more than a permissible percentage.
- 6.85 The basis of the control mechanism will be of the prospective CPI minus X form. "

5.2 The revenue cap form of price control

The regulatory control formula for standard control services proposed by the Commission in its Framework and Approach Decision Paper is a revenue cap. Power and Water welcomes this decision.

Power and Water has developed a formulaic representation of the revenue control mechanism that is of the prospective *CPI-X* form, to provide outcomes consistent with the intent of the Commission's decision:

$$R_{t-1} \times (1 + CPI_t) \times (1 - X_t) \times (1 \pm \text{passthrough}_t) \pm \Delta R_t \geq \sum_{i=1}^n \sum_{j=1}^m p_t^{ij} \times q_t^{ij}$$

Where:

- R_{t-1} is the revenue in year $t-1$
- CPI_t is the annual percentage change in the ABS Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from March in regulatory year $t-2$ to March in regulatory year $t-1$.
- X_t is the allowed real change in revenue from year $t-1$ to year t of the regulatory control period as determined by the Commission, and where X in the first year of the regulatory control period (year 0) is equal to the Po adjustment
- passthrough_t is any pass through amount for year t determined by the Commission, expressed as a percentage of the annual revenue
- ΔR_t is the overs and unders adjustment to revenue in year t
- n is the number of tariff components
- m is the number of network tariffs

p_t^{ij}	is the price of component i of tariff j in year t
q_t^{ij}	is the forecast volume of component i of tariff j in year t
CPI_t	is the annual percentage change in the ABS Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from March in regulatory year $t-2$ to March in regulatory year $t-1$.

5.3 Compliance with control mechanisms

There are two aspects of compliance with the pricing control mechanism that Power Networks will need to demonstrate each year to the Commission. These are:

- Compliance with the pricing side constraint; and
- Compliance with the revenue cap. These matters are described in the following sections.

5.3.1 Compliance with side constraints

Power and Water proposes that the side constraint formula for standard control services would apply to tariff classes not customers, as required by clause 6.18.6 of the Rules. This side constraint formulation is as applied by the AER in recent distribution determinations. A maximum permissible change of 2 per cent on any increase in the weighted average revenue of each tariff class would apply in any regulatory year.

Power and Water will provide further information, to demonstrate that the proposed choice of tariff classes complies with the provisions of clause 6.18.3 of the Rules, in the Power Networks Pricing Proposal. The following three tariff classes are proposed:

- Domestic;
- Commercial (Low Voltage connected); and
- Commercial (High Voltage connected).

The formulaic expression of the side constraint is as follows:

$$(1+CPI_t) \times (1-X_t) \times (1+2\%) \times (1 \pm \text{passthrough}_t) \geq \frac{\sum_{j=1}^m p_t^j \times q_{t,2}^j}{\sum_{j=1}^m p_{t,1}^j \times q_{t,2}^j}$$

Where:

CPI_t	is the annual percentage change in the ABS Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from March in regulatory year $t-2$ to March in regulatory year $t-1$.
X_t	is the allowed real change in revenue from year $t-1$ to year t of the regulatory control period as determined by the Utilities Commission

$passthrough_t$ is the change in approved pass through amounts, expressed as a percentage, with respect to regulatory year t as compared to regulatory year $t-1$, as determined by the Utilities Commission

n the number of tariffs in year t

m the number of components of tariff n in year t

$p_{t,j}^f$ is the proposed price for component j of the tariff class in year t

$p_{t-1,j}^f$ is the price charged for component j of the tariff class in year $t-1$

$q_{t-2,j}^a$ is the actual volume of component j of the tariff class in year $t-2$

5.3.2 Compliance with the revenue cap

With the revenue cap form of control, there will inevitably be a difference between the revenue collected through tariffs, which is based on forecast volumes, and the allowable revenue. As required by the Commission, Power Networks will establish an Unders and Overs account to reconcile this difference.

The balance of the Unders and Overs account would be adjusted for the time value of money. Power Networks proposes that the interest rate applicable to the calculation of the Unders and Overs amounts should be the nominal WACC determined by the Utilities Commission for the regulatory control period. This is the same approach as that established by the AER.

The approach proposed to determine the Unders and Overs account balance each year is shown in the following Table 7.

Table 7 – Unders and Overs calculation

Element	Year t-2 Actual	Year t-1 Expected	Year t Forecast
Opening Balance	$Opening_{t-2}$	$Opening_{t-1}$ $= Closing_{t-2}$	$Opening_t$ $= Closing_{t-1}$
Interest on opening balance	$Opening_{t-2} \times W$	$Opening_{t-1} \times W$	$Opening_t \times W$
Under/over recovery for the year	ΔR_{t-2}	ΔR_{t-1}	ΔR_t
Interest on under/over recovery	$\Delta R_{t-2} \times V$	$\Delta R_{t-1} \times V$	$\Delta R_t \times V$
Closing balance	$Closing_{t-2}$ $= Opening_{t-2} \times (1+V)$ $+ \Delta R_{t-2} \times (1+W)$	$Closing_{t-1}$ $= Opening_{t-1} \times (1+V)$ $+ \Delta R_{t-1} \times (1+W)$	$Closing_t$ $= Opening_t \times (1+V)$ $+ \Delta R_t \times (1+W)$

Where:

$Opening_t$ is the Unders and Overs opening balance in year t

ΔR_t is the difference between allowable revenue and revenue recovered for the year t

W is the nominal Weighted Average Cost of Capital (WACC) determined by the Utilities Commission for the regulatory control period

V is the WACC applicable to a half-year ($V = \sqrt{W + 1} - 1$)
 $Closing_t$ is the Unders and Overs closing balance in year t

Power and Water will set network tariffs each year t to target a closing balance in the account as follows, in accordance with the Commission's decision:

- if $|\Delta R_t| \leq 2\%$ of MAR, the under/over recovery will be cleared within one regulatory year;
- if $2\% < |\Delta R_t| \leq 5\%$, the under/over recovery can be spread over two regulatory years; and
- if $|\Delta R_t| > 5\%$, Power and Water would submit a plan to the Commission detailing how it proposes to clear the balance of the Unders and Overs account.

6 Demand forecasts

Demand forecasts underpin the proportion of the capital expenditure program associated with demand growth. The demand forecasts also have an effect on the forecast operating expenditure, principally through the addition of assets that must be maintained.

The influence of the demand forecasts on network expenditure is twofold:

- The peak demand at various locations on the network (spatial demand) drives the requirement to meet or manage that demand, often through augmenting the capacity of the network; and
- The number of new customer connections has an effect on the expenditure required to construct those connections as well as to augment the upstream infrastructure for the connected load. It also affects the capital contributions and contributed assets received by Power Networks.

Code and Rule requirements

The relevant Code clause is 68(a), which sets out the revenue and price cap principles. When making a determination, the regulator is required to take account of the influence on the revenue requirement of the demand growth that the network provider is expected to service.

The capital and operating expenditure objectives are set out in the Rules at clauses 6.5.7(a) and 6.5.6(a). The Rules require the regulator to accept the expenditure forecasts proposed by a DNSP to meet those objectives, provided that the total of the forecast expenditure “reasonably reflects a realistic expectation of the demand forecast ... to achieve the operating expenditure objectives” (clauses 6.5.7(c)(3) and 6.5.6(c)(3)).

This section describes the development of Power Networks’ forecasts of network demand and demonstrates that they represent a reasonable forecast of future developments, as an input to the capital and operating expenditure programs.

6.1 Economic outlook for the Northern Territory

The current outlook for the global economy is for muted growth compared with recent years, primarily driven by ongoing recession and crisis in Europe and moderating growth in the emerging economies of China and India.

Many sectors of the Australian economy are slowing, with resource-related construction forecast to decline from recent peak levels and the contribution of the resources sector shifting to production and exports. Growth in the non-resource sector and exports will be underpinned by low interest rates and the lower Australian dollar. As a result, overall growth in Australia’s economy will remain at about average rates.

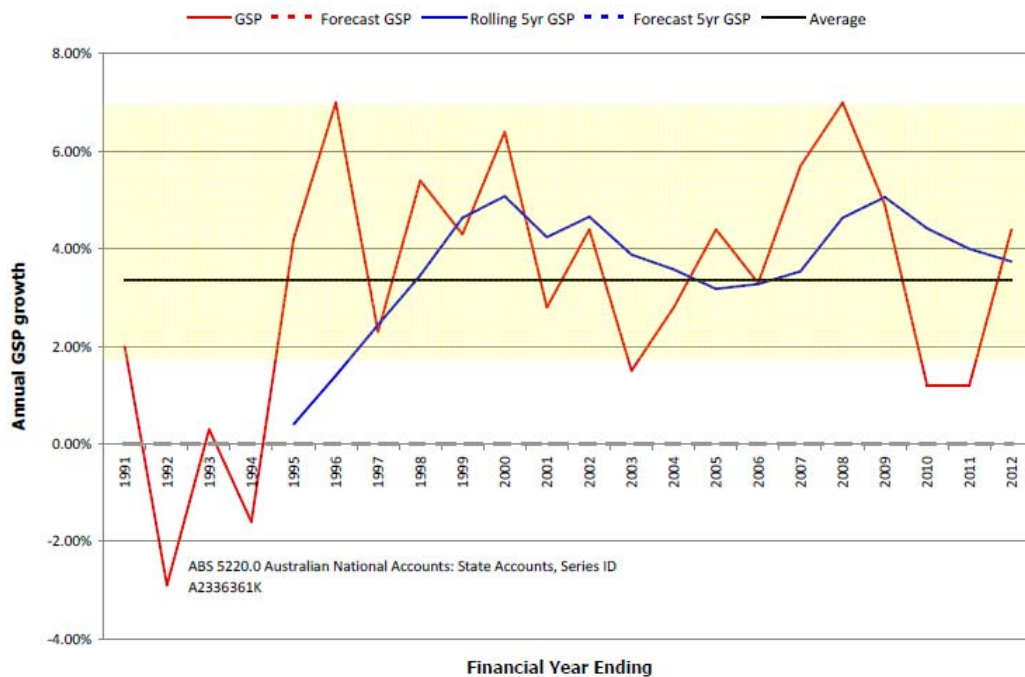
In contrast, economic activity in the Northern Territory economy is proceeding apace. The \$34 billion Ichthys project will not be completed until 2016 and other private engineering construction, equipment and housing investment and international exports are at unprecedented levels. This has led Deloitte to forecast:

“average annual five-year economic growth rate for the Territory through to 2016-17 to be 4.5 per cent. This compares to a national average annual

growth rate of 3.0 per cent and is the highest growth rate of all jurisdictions over this period²⁰.

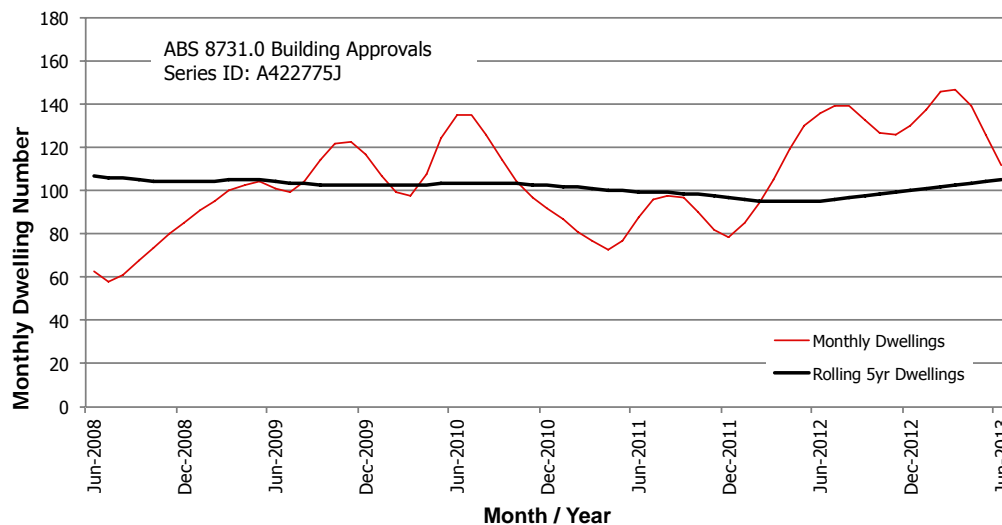
The historical Gross State Product (GSP) is shown in Figure 6. The recent high levels and anticipated above-average trend may be seen.

Figure 6 – Northern Territory GSP



This high level of economic activity is also evident in the Northern Territory Building Approvals, shown in Figure 7.

Figure 7 - Northern Territory building approvals



²⁰ Deloitte Access Economics, Territory Economic Review, July 2013, p. 11.

The Territory's population is also increasing at relatively high rates. Deloitte commented:

"Deloitte is forecasting Territory population growth of 1.8 per cent in 2012/13 and 1.4 per cent in 2013/14. This is above the Territory's growth rate for the past two years, reflecting strengthening international and interstate migration.

In the five years to 2016-17, Deloitte has forecast average annual population growth in the Territory of 1.7 per cent, the third highest of all the jurisdictions behind Western Australia and Queensland. This compares to national annual average population growth of 1.6 per cent.²¹"

The immediate and medium term economic outlook for the Northern Territory is at higher than average and higher than national levels. This economic activity flows through to above average demand for electricity and increased numbers of connections to the network.

6.2 Greenhouse policy, climate change and energy efficiency effects

There is an array of requirements, mainly at the federal level that are imposed as part of the government's response to climate change and the need for energy efficiency. There is also a current element of uncertainty in the future of such schemes as:

- The carbon price, which is now proposed to be aligned with the European trading arrangements and may potentially be abandoned; and
- The ongoing nature of subsidies and inducements for energy efficiency to manufacturers, industry and consumers.

It should be noted that these policies are principally directed at encouraging energy efficiency. This does not directly translate to reductions in peak demand, which is one driver of the network's costs. At this stage, there are two areas in which Power Networks believes there may be a material impact on demand during the 2014-19 regulatory control period:

- Price response; and
- Solar PV installations.

Price response

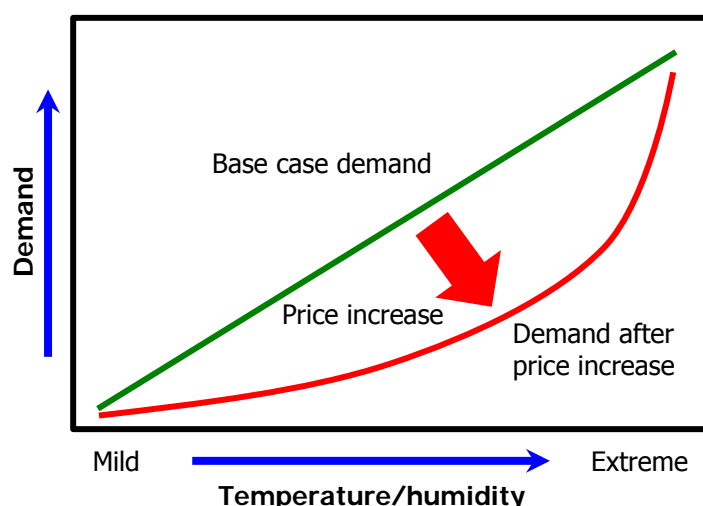
Whilst peak demand for electricity is relatively price inelastic, the relatively large increase in the retail price on 1 January 2013 and further price increases expected during the course of the 2014–2019 regulatory control period is expected to be sufficient to influence energy consumption.

²¹ Ibid. p. 11.

The effect of energy price increases on maximum demand is expected to be much less significant, particularly for the domestic sector. Domestic air conditioning load is a principal contributor to wet season and summer demand and its use in extreme conditions is unlikely to be deterred significantly by energy price increases.

The effect of increasing price on domestic summer demand is illustrated in Figure 8.

Figure 8 – Illustrative effect of price on peak domestic demand



When price is increased, customers will tend to reduce energy consumption in mild weather in response to the price signal, represented by the significant demand reduction at the lower end of the temperature/humidity range in Figure 8 above. However, when the temperature becomes extreme, the higher value placed on comfort will significantly outweigh the small additional energy cost, and consumption reverts to the pre-price rise levels as customers maximise the use of air-conditioning appliances.

An increasing price will impact energy consumption, mainly through reducing the extent of average usage of air conditioning, but will have little effect on the peak demand on very hot and humid days and will further lower the average load factor.

Solar PV installations

The number of solar PV installations connected to the network is rapidly increasing. The growth in recent years is shown in Table 8. These installations are predominantly at domestic and small commercial premises.

Table 8 – Power Networks' Solar PV applications

Year	2010/11	2011/12	2012/13	2013/14*
Solar PV installations	284	318	579	56 (*July 2013)

Solar PV installations reduce the energy transmitted through the network but do not have a proportionate effect on demand. Their output is intermittent and on cloudy

days will vary between minimum and maximum levels as clouds pass overhead. The overall result is expected to be twofold:

- Lowering of the load factor for those customers that are equipped with solar PV installations; and
- Greater uncertainty in the demand placed on the network, as it is dependent upon an additional variable, insolation.

Appropriate allowance has been made in the network demand trends for the price response and for solar PV penetration effects.

6.3 Network demand forecasts

The approach that Power Networks uses to develop its network demand forecasts is described in the Network Demand and Customer Connections Forecasting Procedure. This is included as Attachment 5. It should be noted that Power Networks' 2011/12 demand forecasting approach and outcomes were accepted as reasonable by the Commission in the Power System Review, carried out by consultants Evans and Peck²².

The global demand forecasts provide an indication of the overall trends in Power Networks' regions. They do not directly relate to the incidence of growth related capex but are used as a check to ensure that the sum of the spatial demand forecasts, which influences both capex and opex, are in reasonable alignment.

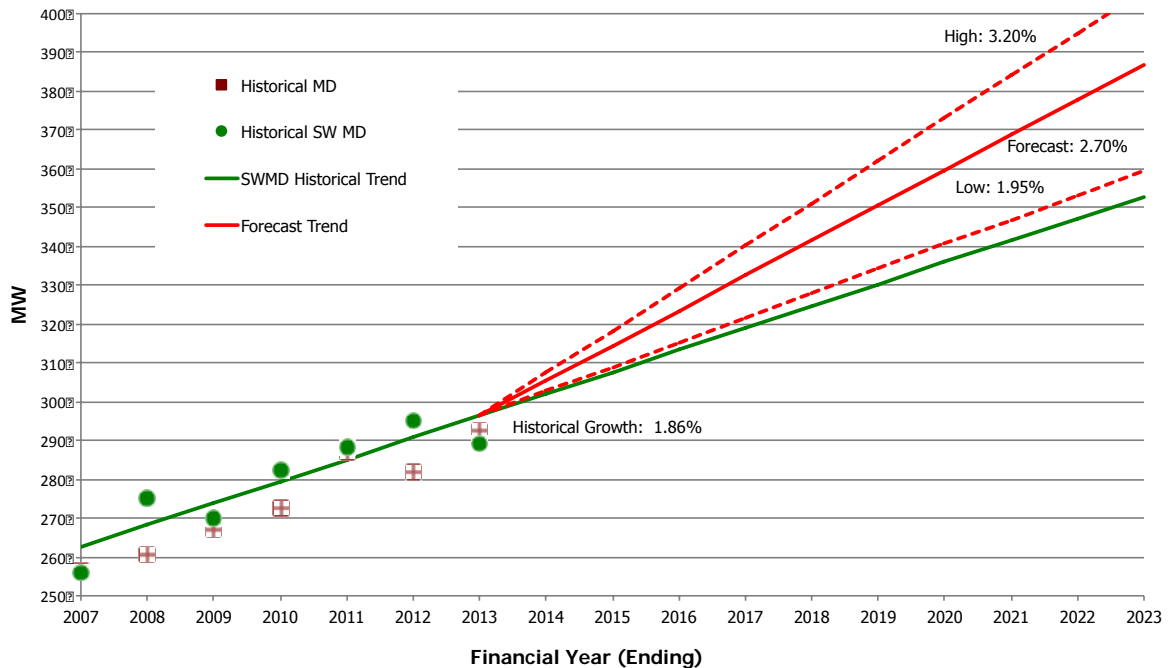
²² Utilities Commission, Power System Review 2011/12, April 2013, pp. 26-28.

6.3.1 Global demand forecasts

Darwin-Katherine

The global demand forecast for Darwin – Katherine, the largest of the regions, is shown in Figure 9.

Figure 9 - Darwin - Katherine system wet season demand forecast



The demand in 2012/13 was significantly lower than forecast and lower than the previous year, which is attributed to:

- The retail price increase of 30 per cent on 1 January 2013 (this increase was subsequently reduced to 20 per cent on 22 March 2013 and backdated to 1 January); and
- The delayed connection of some major loads.

These factors are not expected to lead to a permanent reduction and, particularly having regard to the current and forecast strong levels of economic activity, the forecast demand growth in this system is expected to average 2.7 per cent. This is the same growth as was forecast in 2012/13, from a different starting point. The expected range of growth, based on historical variation in the GSP is also shown in Figure 6.

Alice Springs

The Alice Springs region historical and forecast demand is shown in Figure 10.

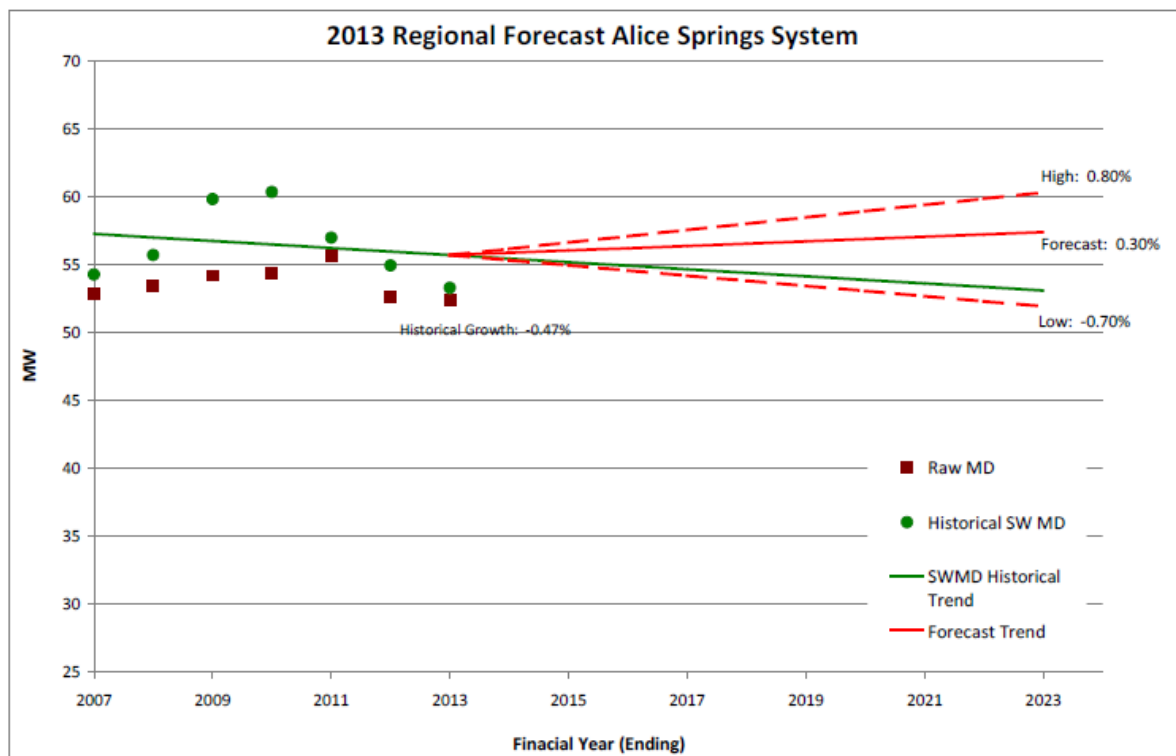
The temperature corrected summer demand indicates a reduction over the last three years, but there is a high penetration of solar PV generation in this region, which is

expected to add volatility. As with the Darwin-Katherine region, the significant price increase on 1 January 2013 may have also had an effect.

Importantly, Alice Springs had a winter peak in 2012/13, for the first time in many years. The day of 3 July 2012 was the coldest day in Alice Springs in 10 years and resulted in a significant peak of 57.5 MW. This demand is above any summer peak in the last five years. This event will require further analysis to determine if this represents a change in consumption patterns or a one-off event.

There are no major developments known to be afoot in this region and in view of the above factors the forecast demand growth for the Alice Springs region has been reduced slightly, from 0.5 per cent to 0.3 per cent.

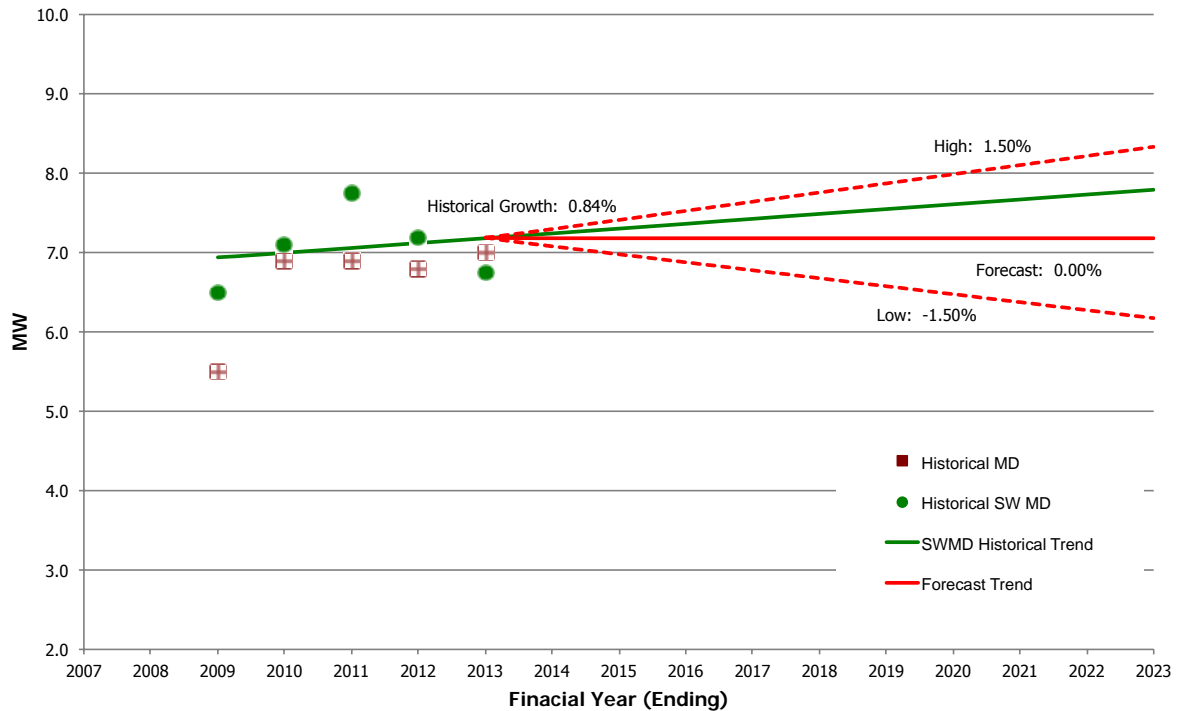
Figure 10 – Alice Springs summer demand forecast



Tennant Creek

Tennant creek is a small region and there is less historical data upon which to base forecast demand growth. The forecast for this region is shown in Figure 11.

Figure 11 - Tennant Creek load forecast



There are no known significant developments taking place in this area and the regional demand is expected to remain static. The small scale of this region is such that a development of 1 MW would represent a major step change in demand.

6.3.2 Spatial demand forecasts

Power Networks produces spatial demand forecasts at two levels – for zone substations and for high voltage feeders. It is these forecasts that drive the need to meet or manage demand and, potentially, to augment the network.

The process that Power Networks follows in developing the spatial forecasts is set out in the Network Demand and Customer Connections Forecasting Procedure in Attachment 5. This process is significantly complicated by the need to adjust the historical demands on zone substations and feeders for load transfers, non-standard supply configurations and significant "block" loads within the network, before establishing growth trends. The demands at zone substations are temperature corrected using the regional sensitivity.

There is a significant amount of detail in the Zone Substation and High Voltage Feeder Demand Forecasts. This information is not reproduced in this document, but instead is included in the RIN Regulatory Templates 6.4 and 6.5 at Confidential Attachment 18.

Forecast reconciliation

The zone substation forecast is reconciled with the regional forecast. The top-down regional forecast and bottom-up zone substation forecasts are developed using different techniques and will never completely align. Moreover, as each zone substation forecast is for a different location, with diverse timing of the local peak, and is expressed in MVA, the sum of the zone substation demands is greater than the regional MW forecast.

What is important, however, is to ensure that the growth trend in the summated zone substation forecast is reasonably in alignment with the regional trend. This reconciliation has revealed that the forecast growth at the zone substation level (after making allowance for the incidence of new block loads) is 3.2 per cent, which is considered reasonable correspondence with the 2.7 per cent projection at the regional level.

A similar reconciliation is carried out at each zone substation, to ensure that the sum of the High Voltage feeder demands corresponds with the total for the substation.

6.3.3 Customer connections forecast

The following is a description of the process by which Power Networks' forecast of customer connections was developed. The forecast used as its basis the historical trends in customer connections and also takes into account the economic indicators described in section 6.1.

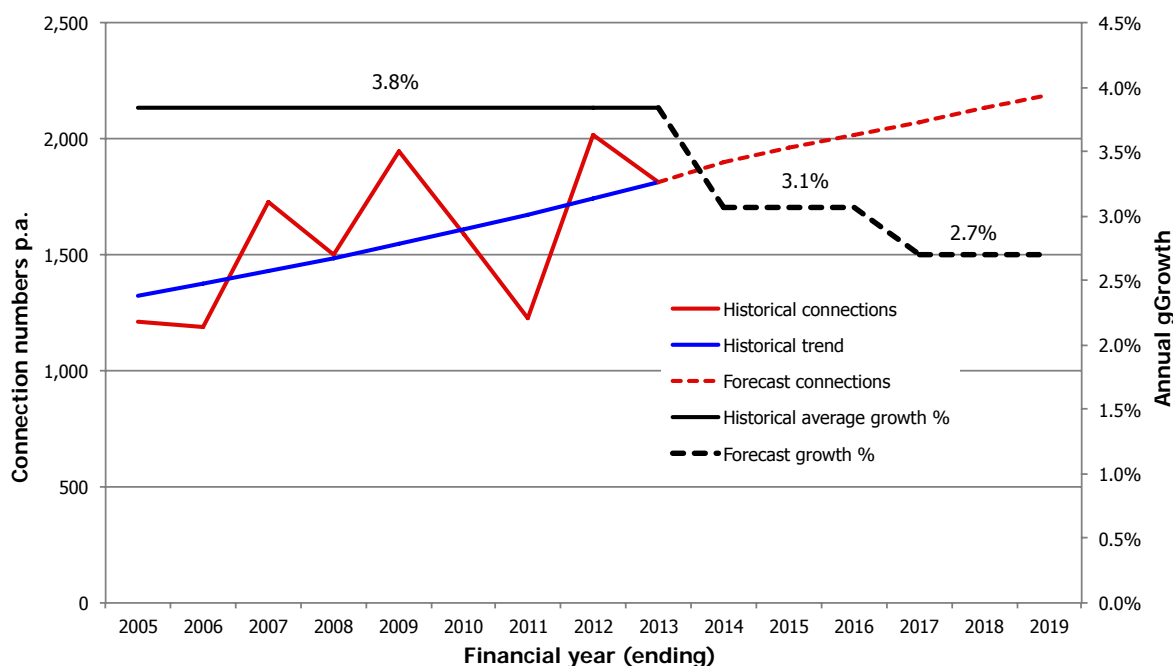
Good statistical correlation was observed between the historical GSP and estimated connection numbers with $R^2 = 0.61$, with the connection numbers lagged by one year. This was the basis on which an adjustment in the forecast customer connection growth rate was made to account for high levels of current economic growth that are expected to continue for another three years.

The base growth rate of 2.7 per cent for customer connections was selected after consideration of the following annual growth rates:

- Population forecast – 1.5 per cent;
- Demand forecast (2012/13 – Darwin-Katherine) – 2.7 per cent;
- GSP average historical growth – 3.9 per cent;
- Connection numbers historical growth – 3.8 per cent; and
- Dwellings - rolling 5 year average – 2.7 per cent.

The forecast base growth thus represents a decrease in the historical average. The current and short term forecast of higher GSP growth was imposed on this base trend. This resulted in a forecast growth customer numbers that declined slightly from 3.1 per cent in the first two years of the 2014-19 regulatory control period to the base level of 2.7 per cent in the final three years. This is illustrated in Figure 12.

Figure 12 – Customer connections forecast



The number of new customer connections is shown in Table 9.

Table 9 – Customer connections forecast

Year	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
New Connections	1,810	1,900	1,960	2,020	2,075	2,130	2,190

6.4 Energy consumption forecast

The energy consumed by Power Networks' customers does not directly affect the network expenditure forecasts. Moreover, with a revenue cap form of price control it does not form part of the Commission's price setting process. The principal function of the energy consumption forecast is to provide an indication to customers of the average price changes that arise from the Commission's determination.

The energy consumption forecast shown in Table 10 is derived from the retail sales forecast and has an average growth rate of 1.0 per cent per annum. Whilst this energy growth rate is significantly less than the demand growth in section 6.3 and customer growth in section 6.3.3, this is in line with trends towards lower load factor observed both in the Northern Territory and other jurisdictions, principally driven by the increasing penetration of solar PV installations.

Table 10 – Energy consumption forecast*

Year	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Energy MWh	1,622,947	1,707,179	1,743,346	1,764,240	1,768,815	1,779,910	1,791,075

*Excluding unmetered consumption.

7 Real cost escalation and CPI

Due to market forces, labour and materials costs may not increase at the same rate as the consumer price index (CPI). Real cost escalation is thus an important driver of Power Networks' forecast capital and operating costs for the 2014-19 regulatory control period. The Northern Territory is currently undergoing a boom in primary industry and natural resource development and, therefore, there is strong competition for labour and construction resources, which is placing upward pressure on costs.

The real cost escalators are a cost input to the expenditure forecasts and must therefore reasonably reflect a realistic expectation of that input.

7.1 Power and Water's estimates of cost escalation

In order to estimate the effects of real cost escalation, Power and Water has engaged experienced consultants to provide expert advice. Deloitte Access Economics (DAE) advised on labour cost escalation and Sinclair Knight Merz (SKM) advised on materials cost escalation. Their respective reports are included as Confidential Attachment 20 and Confidential Attachment 21 to this Proposal.

This effect of competition for resources is particularly significant in the Northern Territory. DAE has stated that:

"With the Northern Territory's resources boom now in full swing, the overall outlook is for strong wage growth in the near term as the resources boom puts upward pressure on wage negotiations both directly and indirectly. The utilities and professional services sectors are estimated to be currently experiencing wage growth in the order of one percentage point higher than the Territory average amid a period of strong demand from the resources sector – which competes with the utilities sector for its workforce..... that's

Code and Rule requirements

Real cost escalators are a key input to Power and Water's capital and operating expenditure forecasts. They must therefore conform to the Code and Rule requirements concerning these forecasts.

Clause 68 of the Code requires the regulator, when setting a revenue cap, to have regard to:

"the provision of a return on efficient capital investment undertaken by the network provider in order to maintain or extend network capacity that is commensurate with the commercial and regulatory risks involved"; and

"the right of the network provider to recover reasonable costs incurred by the network provider in connection with the operation and maintenance of the network ..."

Real cost escalation is one cost that will be incurred by the network provider and, if not factored into expenditure forecasts, will result in a reduced return on assets and a failure to recover reasonable costs.

The Rules require the AER to accept a DNSP's operating and capital expenditure forecasts if they reasonably reflect the associated expenditure criteria. The relevant expenditure criteria in clauses 6.5.6(c)(3) and 6.5.7(c)(3) is:

"a realistic expectation of the demand forecast and cost inputs required to achieve the capital/operating expenditure objectives."

*what happens when a \$34 billion LNG project starts construction in an economy with annual income of \$19 billion.*²³

In this environment, escalation at CPI no longer reasonably reflects a realistic expectation of the movement in some of the labour and equipment costs.

7.2 Labour cost escalation

There are two main alternative approaches to estimating the real escalation in labour costs. These are the consideration of the Labour Price Index (LPI) and Average Weekly Ordinary Time Earnings (AWOTE). In its recent determinations, the AER has expressed the view that the LPI provides the better estimate of escalation and has used the LPI to adjust forecast costs. For example:

"... the AER considers:

- the labour price index (LPI) provides a better measure of labour cost changes compared to AWOTE;*
- real labour cost escalation should not be productivity adjusted due to systemic issues in measuring and forecasting productivity.²⁴ "*

DAE has provided several recent estimates of labour cost escalation for the AER in its recent determinations and has used their preferred approach of estimating the LPI.

DAE first derived an overall picture for how the LPI will move from its in-house macro-econometric model of the Australian economy. The remainder of the modelling then determined how the LPIs of specific industries, States and industries within states will grow in relation to this value. The key inputs to the overall LPI are:

- business sector output gap;
- real exchange rate;
- import prices (including oil prices);
- monetary policy reaction function;
- average quarterly wages; and
- underlying consumer price index.

The specific labour component is primarily based on the Australian Bureau of Statistics (ABS) estimates of Labour Price Index (LPI). DAE describe the LPI as an anchor to overall wage rates across the economy. From this initial index, the model adds in deviations from the average. Three key factors drive these wage differentials:

- Business cycle factors: Deviations in industry and State performance from the national average. Faster growing industries and States will tend to see faster

²³ Deloitte Access Economics, Labour cost escalators in the Northern Territory, 11 May 2013, p.1

²⁴ AER, Draft decision – Murraylink Transmission determination 2013–14 to 2022–23, November 2012, p. 3.

growth in wages and vice versa. In this model, the key factor is how fast the industry (or State) is growing relative both to the national average, as well as to historical averages.

- Productivity factors: The model assumes that industries with faster growth in productivity will see faster growth in wages – workers across an industry being rewarded for increasing the average amount of output per employee faster than the national average.
- Competition (relative wage) factors: Depending on the nature of the industry, workers will have skills that are relatively more or less transferable to other sectors where wages may be rising faster than in their own. This will tend to limit the ability of wage rates to diverge. For example, as wage rates in mining rise higher, companies in the construction sector may be forced to pay higher wages to keep their staff. Similar factors operate across States – although they are likely to be less significant (and react only to relatively larger discrepancies in wages).²⁵

DAE also notes that some manual adjustments may be made. For example, they assess the impact of recent Enterprise Bargaining Agreements as an indicator of recent wage activity not already factored in to the model.

Power and Water's Enterprise Bargaining Agreement (EBA) expired on 9 August 2013 and was the subject of negotiation between the parties. An extension to the agreement has been negotiated until August 2015.

The internal labour escalators for 2013/14 and 2014/15 are based on Power and Water's 2013/14 Statement of Corporate Intent, which is based on Power and Water's recently extended EBA.

The internal labour escalators from 2015/16 onwards are those developed by DAE.

Labour cost escalators are set out in Table 11.

Table 11 – Real labour cost escalators

Year	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Internal labour	1.8%	1.7%	1.0%	0.6%	0.9%	1.0%
External labour	0.4%	1.0%	1.1%	0.9%	1.0%	1.1%

These escalators have been used to prepare the capex and opex forecasts.

²⁵ DAE op. cit., p. 16.

7.3 Materials cost escalation

In some recent determinations, the AER has estimated the real cost escalation of materials using its internal resources. An example of this can be seen in the Aurora determination²⁶. Power and Water engaged SKM to develop material cost escalators that are specific to the Northern Territory. SKM's approach to materials cost escalation for the Victorian distributors was reviewed by the AER and accepted with some changes²⁷.

SKM has incorporated improvements to its modelling method when there was a clear need, particularly in response to regulatory precedents and as improved cost information becomes available.

In its report on Northern Territory cost escalators for Power and Water, SKM has noted:

*"SKM confirms that its method for modelling the forecast changes in the costs of materials used in PWC's capital and operating expenditure forecasts is consistent with the approach accepted by the AER in its recent decisions."*²⁸

Methodology utilised for the materials escalators by SKM

The methodology employed to determine the materials escalators has forecast movements in the price of key components with 'weightings' for the relative contribution of each of the components to final equipment/project costs.

²⁶ AER, Draft Distribution Determination - Aurora Energy Pty Ltd 2012–13 to 2016–17, November 2011, Attachments 5 and 6.

²⁷ AER, Final decision - appendices - Victorian electricity distribution network service providers Distribution determination 2011–2015, October 2010.

²⁸ SKM, Power and Water Corporation - Annual Real Cost Escalation Forecast 2012/13 - 2018/19, p.8.

The cost drivers used in SKM’s model, their major application and their reference sources is shown in Table 12.

Table 12 – Underlying key cost drivers*

Cost Driver	Application (mostly used for)	Sources
Aluminium, Steel, Copper, Oil	Primary equipment, structure, overhead conductor, cables,	London Metal Exchange, Consensus Economics, UK-MEPS, Bloomberg US-EIA, CME-Nymex
Foreign exchange, import TWI	Protection & control, switchgear, insulators, fittings	RBA, AER, NAB Research
Construction Index	Civil, foundation, building	Australian Construction Industry Forum
Australian CPI	All	ABS, RBA
US CPI	All imports	US-Bureau of Labour Statistics, US-Congressional Budget Office

*With carbon price mechanism on locally manufactured material.

In order to remain current, forecast positions of the key cost drivers within the SKM model are updated for each assignment.

The SKM model utilises a methodology of linear interpolation between spot market prices, available forward contract prices and other reputable sources to develop the key drivers.

Appropriate weightings are assigned to each cost driver to enable their forecast movement to be used to estimate the price movement in each network asset.

Underlying material cost escalators

The underlying material cost drivers that SKM has estimated are shown in Table 13. These escalators include the effect of the CPM on locally manufactured material.

Table 13 – Real escalation of underlying network material cost drivers

Cost driver	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Aluminium	-11.60%	6.67%	4.27%	-4.72%	4.86%	5.07%	4.76%
Copper	-7.45%	2.95%	0.82%	-7.87%	0.89%	-1.46%	-2.00%
Steel	-9.82%	9.65%	1.83%	-9.02%	0.46%	2.24%	3.39%
Oil	-5.02%	9.25%	0.33%	-2.61%	5.07%	3.02%	1.99%
Construction costs	-2.53%	-0.83%	-0.62%	-5.05%	-0.33%	0.15%	-2.40%

Real materials cost escalators

The real materials cost escalators for Power and Water’s capital and operating costs are derived from weighted combinations of the underlying cost escalators for network materials in Table 13.

The real materials cost escalators forecast by SKM are set out in Table 14 (capex) and Table 15 (opex). These escalators include the effect of the Carbon Price Mechanism (CPM) and have been aggregated into the RIN categories.

Table 14 – Real materials cost escalators (capital expenditure)

Year	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
System Assets						
Transmission terminal station	1.3%	0.1%	-3.4%	0.4%	0.5%	-0.5%
Zone substations	1.4%	0.1%	-3.6%	0.4%	0.5%	-0.5%
Transmission lines	3.6%	0.9%	-4.9%	1.0%	1.3%	0.8%
Distribution mains	4.1%	1.1%	-3.1%	1.5%	1.6%	1.6%
Distribution substations	3.9%	0.9%	-3.5%	1.1%	1.1%	1.1%
Metering	1.3%	0.1%	-0.8%	0.5%	0.3%	0.2%
Secondary systems	1.3%	0.1%	-0.8%	0.5%	0.3%	0.2%
Other	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Non-System Assets						
IT and Communication	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Motor Vehicles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Plant & Equipment	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Other	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Table 15– Real materials cost escalators (operating and maintenance expenditure)

Year	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Operating and maintenance expenditure	4.0%	0.6%	-3.2%	1.4%	1.1%	0.9%

Power and Water has applied these real material cost escalators to the capital and operating expenditure forecasts in this Proposal.

7.4 Consumer Price Index

An estimate of CPI is required for the 2014-19 regulatory control period, to enable the indexation of costs within the regulatory model (the NTRM). Annual revenues from the Commission's determination will be adjusted for out-turn CPI using the regulatory control formula set out in section 5.2, so the assumed CPI will not affect the revenue outcome. Nevertheless, this estimate of CPI provides an indication of the Power Networks' nominal revenues and prices.

The Commission (and the AER) has adopted the practice of indexing revenues in the regulatory control formula using the ABS sequence for the weighted average of eight capital cities²⁹. Accordingly, Power and Water has adopted Deloitte's estimate of the Australian CPI movement in the RIN template and modelling. This is shown in Table 16.

Table 16 – Consumer Price Index forecast

Year	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Percentage movement	2.7%	2.8%	2.7%	2.7%	2.5%	2.4%

²⁹ Australian Bureau of Statistics, 6401.0 - Consumer Price Index, Australia.

8 Forecast capital expenditure

This chapter of the Proposal details Power Networks' capital expenditure forecast for the provision of standard control services in the 2014-19 regulatory control period.

Power Networks considers that this expenditure is required to meet the Code requirements and the capital expenditure objectives described within the Rules.

This chapter includes:

- A summary of the relevant Code and Rule requirements;
- A review of the capital expenditure that Power Networks is forecast to incur in the 2014-19 regulatory control period;
- A description of the process by which the capital expenditure forecast for the 2014-19 regulatory control period has been developed;
- A description of the inputs to the capital expenditure development process including the capital governance and asset management frameworks;
- The forecast capital expenditure for the 2014-19 regulatory control period associated with key categories of expenditure, being:

- Network User Initiated capital expenditure;
- Augmentation capital expenditure;
- Replacement capital expenditure;
- Reliability and Quality capital expenditure;
- Compliance, Environment and Safety capital expenditure; and

Code and Rule requirements

The Code does not specifically identify the requirements for the capital expenditure forecast used to determine network revenues. Rather, it sets out the high level objectives of price regulation, including in clause 63(a) achieving the efficient costs of supply. Clause 68(a) requires the regulator to take into account the demand growth that the network provider is expected to service.

Section 6.5.7(a) of the Rules requires that Power Networks submit a forecast of capital expenditure to meet the capital expenditure objectives over the relevant regulatory period, being to:

1. Meet or manage the expected demand for standard control services over that period;
2. Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;
3. Maintain the quality, reliability and security of supply of standard control services; and
4. Maintain the reliability, safety and security of the distribution system through the supply of standard control services.

Further, section 6.5.7(c) of the Rules requires the AER to accept Power Networks' proposed capital expenditure if it reasonably reflects:

1. The efficient costs of achieving the capital expenditure objectives;
2. The costs that a prudent operator in Power Networks' circumstances would require to achieve the capital expenditure objectives; and
3. A realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

These are referred to as the capital expenditure criteria.

- Non-Network capital expenditure.

Please note that only material projects are described under each of the key categories of expenditure.

- Assurance that the forecast capital expenditure program can be delivered.

Power Networks has demonstrated its compliance with the capital expenditure criteria in each of the forecast capital expenditure justification documents provided at Confidential Attachment 23.

It should be noted that the costs incorporated within Power Networks' forecast capital expenditure for the 2014-19 regulatory control period are consistent with maintaining standard control services at appropriate levels of security and reliability.

In particular, Power Networks acknowledges that there has been some deterioration in reliability levels throughout the 2009-14 regulatory control period, based on the 2012 Electricity Standards of Service Code³⁰. The forecast of the capital expenditure required for the delivery of standard control services during the 2014-19 regulatory control period is predicated on Power Networks restoring the reliability of its electricity distribution network to former levels.

8.1 Framework and Approach Decision

In its Framework and Approach Decision Paper, the Commission confirmed its intention to assess the prudence and efficiency of Power Networks' capital expenditure forecasts in accordance with clause 6.5.7 of the Rules. That is, the total of the expenditure forecast would be assessed against the capital expenditure objectives and accepted by the Commission if the forecast meets the capital expenditure criteria.

8.2 Capital expenditure in the 2009-14 regulatory control period

The forecast and actual capital expenditure during the 2009-14 regulatory control period is shown in Table 17.

Table 17 – Capital expenditure 2009-14 (\$ million, nominal)

Year	2009/10	2010/11	2011/12	2012/13 (F)	2013/14 (F)
Actual capital expenditure	\$85.02	\$88.76	\$78.77	\$111.22	\$91.94

It should be noted that the Commission did not use a building block approach to determine revenues in 2009 and instead used a Total Factor Productivity (TFP) based approach.

³⁰ Power Networks has applied the 2012 Electricity Standards of Service Code using SCNRRR Feeder Categories and IEEE1366 MED Exclusions.

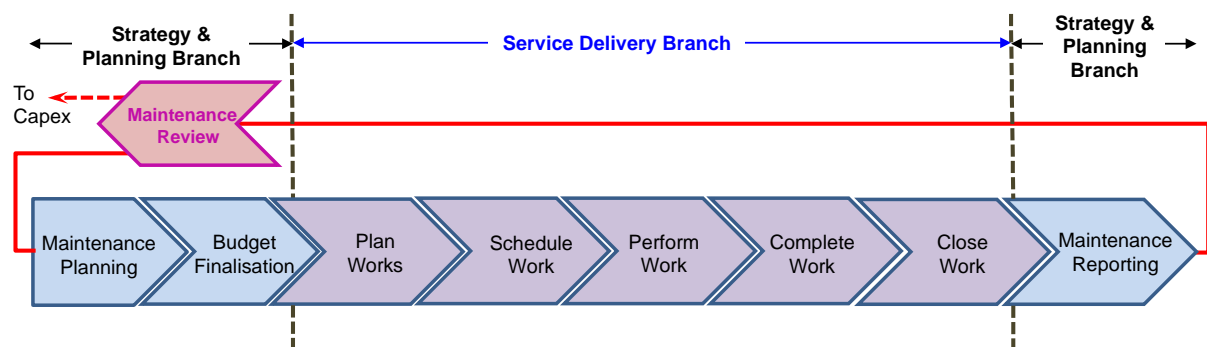
In May 2012 the Commission permitted the pass through of capital and operating costs directly associated with the recommendations of Mervyn Davies' report concerning the failures at Casuarina Zone Substation³¹.

Power Networks' total capital exceeded the total of the regulatory allowance plus the cost pass through. The principal reason for this is that the extensive condition monitoring program (the Remedial Asset Maintenance Program or RAMP) established following the Casuarina incident identified a significant number of assets that were in poor condition and posed security, reliability and some cases, safety and environmental risks. The additional expenditure was largely as a result of prudent actions taken following the identification of high risk equipment.

8.3 Capital expenditure development process

Power Networks has developed detailed asset maintenance processes that ensure 'best practice' asset management and the clear identification of the responsibilities and appropriate handover points between the teams involved. A high level flow diagram for the asset maintenance cycle is shown in Figure 13.

Figure 13 - Asset management cycle



Importantly, Figure 13 highlights the 'feedback loop', whereby the maintenance reporting function provides critical data on the asset condition of Power Networks assets. As this data is processed consideration is also given to the performance of 'like' assets in national and international jurisdictions. Other factors such as safety, expected loading and strategic network objectives are also considered in the review of maintenance planning practices and, where appropriate, investment in assets and their renewal or refurbishment.

Power Networks' Asset Management Strategy identifies the core preventative maintenance and condition monitoring tasks for each asset class³². Analysis of the risks of asset failures is undertaken using a standard Failure Mode, Effects and Criticality Analysis (FMECA), and is performed with input from asset maintainers and planners, safety officers, test & protection personnel, engineering and external consultants. This identifies the risks that are then mitigated through a Reliability

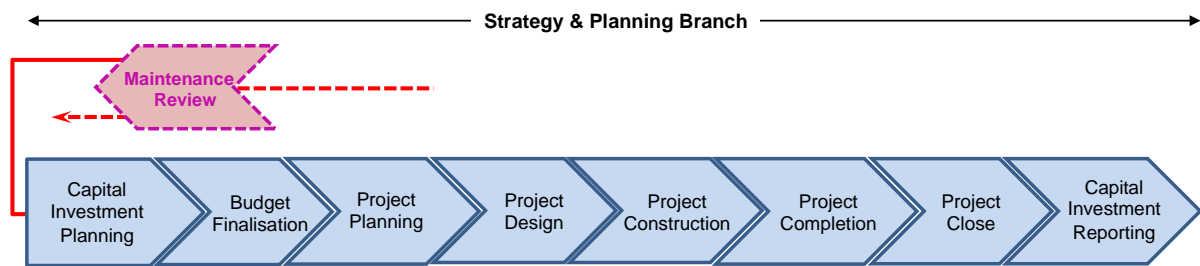
³¹ Utilities Commission, Cost Pass Through Application Final Determination, May 2013.

³² Power Networks' Asset Strategies Procedure (Confidential Attachment 29).

Centered Maintenance (RCM) approach. The outcomes of this approach have been previously verified in a benchmarking exercise with two other Australian distribution utilities.

The equivalent high-level flow diagram for the asset capital expenditure process is shown Figure 14. Although the responsibility for this activity lies within the Strategy and Planning Branch, the activities of different work teams are identified in the detail of the process flow.

Figure 14 - Capital expenditure process



The capital expenditure process in Figure 14 has been used in developing the capital expenditure programs in this Proposal. The figure shows the stages in the development of a project, from planning inception through to completion and the reporting of assets. Feedback from the maintenance review (Figure 13) is used to develop the refurbishment and replacement elements of the program.

8.3.1 Material projects and programs

As required by the Commission's RIN, the forecast capital expenditure has been subdivided into material projects and programs. The expenditure materiality thresholds that have been established by the Commission are:

- (a) \$2 million in the case of a project which relates to either of the standard control capex categories *non-network—IT & communications capex*, *non-network—property capex*, *non-network—plant & equipment capex*, *non-network—motor vehicles capex*, *non-network—other capex*; or
- (b) \$5 million in the case of a project not covered by paragraph (a).

A detailed expenditure evaluation and demonstration of the prudence and efficiency of expenditure has been submitted for each of the individual material projects and programs, as part of the information accompanying this Proposal. These Capital Expenditure Forecast justification documents are provided at Confidential Attachment 23.

8.4 Forecast network user initiated capital expenditure

Below is a brief outline of the material projects initiated by network users over the forthcoming regulatory control period.

Customer Augmentation and Network Extension Program (Sub8272)

Customers seek network extensions or upgrades and to the extent that the investment is supported by future increased tariff revenue from the customer, Power Networks fund and construct the associated assets. The current Distribution System Extension Policy (DSEP) and Network Capital Contributions Policy do not influence this capital expenditure but do affect the level to which these costs are met directly by customers rather than through tariffs.

The existing DSEP scheme heavily subsidises customers for new network connections in the rural areas and for upgrades required to existing electricity services. It also subsidises developers, as Power Networks carries out much development work in return for payments that do not meet the costs.

The revised Networks Capital Contributions Policy (NCCP) to commence in July 2014 (subject to the Commission's approval) will reduce the existing subsidies and cross-subsidisation, and ensure more equitable outcomes for both new and existing Network Users. Therefore, a greater proportion of the costs of customer augmentation and extension will be funded by customers and developers.

Based on the assumption that the revised NCCP will be approved by the Commission, and from an analysis of historical spend, the forecast spend for the 'Customer Augmentation and Network Extension Program' is estimated to be \$37.5 million (\$2012/13) in the 2014-19 regulatory control period.

Robertson Barracks Fourth Dedicated Line (PRD30510)

Robertson Barracks is a major Defence Barracks located near Palmerston in the Darwin region. The Barracks are currently supplied by three dedicated feeders with some additional support from a fourth feeder to provide a total firm capacity of 13.4 MVA.

To date, load growth at the site has been lower than the customer's expectation and assuming existing growth rates on the relevant feeders, Power Networks' forecasts indicate that the existing firm capacity will be exceeded in 2018/19. Given the size of this customer (Defence), Power Networks expects to fund this project without the requirement for a capital contribution, as the cost of the development would be recouped through future tariffs.

This project is estimated to cost \$4.6 million (\$2012/13) with all expenditure in the 2014-19 regulatory control period.

Externally Funded Projects

Externally funded projects are projects that are requested by a customer for which they pay for in full and Power Networks completes the work, but the ownership of the asset resides with Power Networks. These are often for a second supply or for works over and above works specified under legislation. The forecast spend, based on historic spend, is estimated to be \$5 million (\$2012/13) in the 2014-19 regulatory control period.

8.5 Forecast augmentation capital expenditure

Below is a brief outline of the material projects largely, or wholly, driven by changes to, or forecast changes to, the existing pattern or profile of demand over the forthcoming regulatory control period.

Darwin: Construct Archer to Palmerston 66kV Transmission Line (PRD30513)

The current standard weather maximum demand load forecast for the Darwin region indicates an expected growth rate between 1.95 per cent and 3.2 per cent in the long term. A disproportional amount of this growth is expected to occur in the Palmerston and rural areas of Darwin. The transmission utilisation and contingency analysis indicates that constraints on existing transmission lines may occur as early as 2015/16. To alleviate these constraints a number of options are under consideration with the preferred option being the construction of a new transmission line between Archer and Palmerston Zone Substation.

This project is estimated to cost \$12.0 million (\$2012/13), with \$11.8 million expenditure in the 2014-19 regulatory control period.

Failure to address this problem will result in transmission line sections under contingency conditions (i.e. the loss of another transmission line during peak demand periods) exceeding thermal ratings. Under this condition the system controller would be required to shed load.

Darwin: Construct East Arm Zone Substation (PRD30309)

Power Networks has closely monitored the commercial and industrial development of the East Arm area over the last 10 years as indications of significant development in the area have grown. During this time, construction of additional power infrastructure has been deferred until substantial development was underway and subsequent load growth was evident. Recent investments in the gas industry and associated industries, such as marine support, have provided the strongest development signs to date and a number of companies have now been established in the Darwin Business Park, situated in East Arm, and the surrounding area to take advantage of the nearby rail and port infrastructure. The East Arm area is currently expanding at a modest rate. However, it has the potential, with short notice, to grow substantially and beyond Power Networks' current system capabilities with the addition of just one or two new major industrial customers.

The East Arm area is currently supplied with power from Berrimah Zone Substation. The firm capacity of Berrimah Zone Substation has already been exceeded and the area load security is maintained during peak times through an ability to transfer other loads to Palmerston Zone Substation. This option is becoming increasingly limited as load increases at the Palmerston Zone Substation. In addition to the constraints at Berrimah Zone Substation, the high voltage feeders in the East Arm area are also approaching the 11kV feeder N-1 firm capacity and can experience low voltage during contingency conditions.

Given the capacity limitations of the existing systems and the potential for additional growth, it is prudent to progress this investment option now. The timing of the development is based on current load forecasts. However, the progression of the substation development, including the potential for lower-cost interim solutions and the potential for deferral of the works using demand management initiatives will be kept under review.

The proposed solution is to install an interim skid mounted or mobile substation in the near term to ensure demand can be met. This will defer the requirement to build a new zone substation to the outer years of the 2014-19 regulatory control period. This temporary solution is estimated to cost \$4.3 million (\$2012/13). A substantial portion of this is the civil and electrical works for the 11kV feeder connections, which would be re-routed at minimal cost to the adjacent zone substation site.

The total project, including the interim solution, is estimated to cost \$30 million (\$2012/13), with \$18 million (\$2012/13) expenditure in the 2014-19 regulatory control period.

Failure to proceed with the interim solution will expose Power Networks to a situation in the short term where it would be unable to meet new customer loads in the East Arm area.

8.6 Forecast replacement capital expenditure

Below is a brief outline of the material projects largely, or wholly, driven by the need to maintain the functionality of the existing asset base, irrespective of changes to the pattern or profile of demand, over the forthcoming regulatory control period.

Darwin: Rebuild McMinns 66/22kv Zone Substation (PRD30117)

McMinns Zone Substation was constructed in the 1970s and is now aged and in poor condition. The outdoor 66kV and 22kV switchgear are at the end of their serviceable life. These assets have a significantly impact on network reliability, and maintenance costs are continuing to increase in an effort to keep them in service.

The project is estimated to cost \$27.3 million (\$2012/13), with \$17.7 million (\$2012/13) expenditure in the 2014-19 regulatory control period.

This substation is critical to the supply of power to Darwin's rural area. Deferral of this project will expose most of the rural customers to the risk of major power outages and this risk will increase with time as the equipment continues to age and the load requirements increase.

Darwin: Replace Casuarina 66kV Outdoor Switchyard (PRD30115)

Casuarina Zone Substation has in recent years experienced a number of major asset failures resulting in significant outages. While the 11kV equipment has been replaced, the 66kV switchgear is now over 40 years of age with the circuit breakers having industry known reliability concerns. The transformers are also nearing end of life and are generally in poor condition.

This project is estimated to cost \$17.1 million (\$2012/13) with \$16.5 million (\$2012/13) expenditure in the 2014-19 regulatory control period.

Deferral of this project will expose customers to the risk of major power outages and this risk will increase with time as the equipment continues to age.

Darwin: Replace Berrimah Zone Substation (PRD30402)

Berrimah Zone Substation was commissioned in the late 1970s and many of the assets that are currently installed are approaching the end of their serviceable life. In particular, the 66kV switchyard consists of five ASEA HLC minimum oil breakers similar to those located at Casuarina and McMinns Zone Substations, with the same reliability concerns. The power transformers are in an 'aged' condition with high moisture levels, a history of oil leaks and poor oil furan test results, indicating they are nearing end of life.

Replacement of the switchboard is also recommended as it is not arc rated and does not have any busbar protection scheme, therefore posing safety concerns for operational staff.

This project is estimated to cost \$26.9 million (2012/13) with \$26.8 million (2012/13) expenditure in the 2014-19 regulatory control period.

Deferral of this project will expose customers to the risk of major power outages and this risk will increase with time as the equipment continues to age and the load requirements increase.

Darwin: New Mitchell Street Switching Station (PRD30600)

The main objective of this project is to ensure that a secure supply of electricity is available to the Darwin CBD at all times. Power Networks is currently leasing the existing switching station site from Darwin City Council and must vacate the land by 2018.

After investigating a number of sites for a third zone substation in the Darwin CBD, a block of land adjacent to the existing Mitchell Street Switching Station was purchased from Darwin City Council in 2008. Given the age and the current requirement to relocate all assets, the construction of a new switching station on the adjacent land is the most likely solution. This 'green field' full replacement solution is likely to be the lower risk, most effective long-term solution and, as such, is the basis of the costing.

This project is estimated to cost \$15 million (\$2012/13) with all expenditure in the 2014-19 regulatory control period.

Despite previous indications that Power Networks must vacate the existing site before 2018, Power Networks will revisit the issue with Darwin City Council to seek an extension of the lease to defer works if possible. Should the Utilities Commission not allow this expenditure, Power and Water would seek to have this project considered as either a cost pass through event or as a contingent project, if a lease

extension is not possible. The contingent project provision in clause 6.6A.1(b)(2)(iii) of the Rules has a threshold of \$30 million, which is inappropriately high for Power Networks' business and would need to be lowered.

Alice Springs: Install Sadadeen 11kV Switchboard (PRA30520)

Power Networks currently share a common 11kV switchboard located at Ron Goodin Power Station, directly adjacent to the Sadadeen Zone Substation, with Power and Water Generation. This switchboard is considered to be at the end of its serviceable life, as is the entire Ron Goodin Power Station.

PWC Generation will be retiring generating plant in line with the expansion of the new Owen Springs Power Station, leading eventually to the closure of Ron Goodin Power Station. Power Networks is planning to relocate the 11kV feeders from Ron Goodin to a new switchboard located at the Sadadeen Zone Substation site prior to this closure, and in consideration of the age and condition of the current Ron Goodin 11kV switchboard.

This switchboard was commissioned in 1969 and in 2012 the oil circuit breakers were retrofitted with vacuum circuit breakers in response to the removal of oil switchgear following the failure at Casuarina Zone Substation. Despite these newer elements, the switchboard itself is still considered to be at its end of life and likely to experience an increased rate of failures. The installation of a new switchboard would be entirely for Power Networks distribution, the switchgear would be modern, have improved design for reliability, maintenance and operations as well as being safer, with features such as arc-containment. This project is estimated to cost \$5.6 million (\$2012/13) with all expenditure in the 2014-19 regulatory control period.

This project is required to maintain the quality, reliability and security of supply to the Alice Spring town centre via asset renewal. This switchboard feeds over half the load of Alice Springs and failure to proceed with this project exposes Alice Springs customers to extended outages.

Alice Springs: Replace Sadadeen 22kV Switchboard (PRA30510)

Power Networks has three Yorkshire YFS6 22kV switchboards located at Manton, Katherine & Sadadeen Zone Substations. This make and type of switchgear has a known design defect that results in high partial discharge levels that significantly reduces its original design life, particularly in areas of high humidity. Power Networks has experienced a high number of failures at both Katherine and Manton Zone Substations. In response to these failures, Power Networks has replaced the Yorkshire switchgear at Katherine Zone Substation and expects to complete switchgear replacement at Manton Zone Substation in 2013.

The failure of the Yorkshire bus-section panel at Sadadeen Zone Substation in 2010 lead to the blackout of Sadadeen and Lovegrove Zone Substations for over a six hour period, and resulted in a review of the Sadadeen switchgear replacement program. A number of remedial and additional maintenance actions were immediately taken to ensure improved environmental controls of the site and maximise the life of the

equipment, including water sealing of cables ducts and trenches, re-sealing of the concrete building, installation of continuous online partial discharge monitoring and the installation of a de-humidifier. While these actions have significantly slowed the partial discharge failure mode, the problems are inherent to the equipment and further failures will occur. As such, replacement of this board is recommended.

This project is estimated to cost \$5.0 million (\$2012/13) with all expenditure in the 2014-19 regulatory control period. This project will ensure a safe, reliable, high quality power supply for customers in Alice Springs, as well as enhancing operational safety and function.

Asset Replacement and Upgrade Program (Sub8274)

From time to time, specific asset classes or types reach end of life or are found to have significant operational or safety defects and require replacement or augmentation. Other network safety improvements may also be identified requiring capital investment. A number of ongoing and new programs to replace or upgrade affected assets are required over the forthcoming regulatory control period. Some examples of this work include:

- Transmission line earthing and clearance rectification;
- Replacement of distribution switchgear;
- Replacement of cast iron cable potheads;
- Distribution pillar box replacements; and
- Zone substation equipment replacements.

This program is estimated to cost \$21.0 million (\$2012/13) in the 2014-19 regulatory control period.

The various programs identified have been assessed as necessary to provide ongoing safe and reliable supply to customers, and to remove equipment that presents an unacceptable risk to personnel if it remains in operation.

High Voltage Cable Replacement Program (Sub8260)

A significant proportion of high voltage cables in the Darwin northern suburbs are reaching the end of their expected life and are in a poor condition. Specific types of cables installed in the early 1980s are known to industry as being particularly susceptible to moisture ingress, corrosion and subsequent failures.

Faulted cables may stay out of service for extended times while faults are located or repairs performed. Repair of cables in poor condition is often very difficult, further extending the time the cable is unavailable. When multiple cables are unavailable in the same area, significant network constraints arise reducing the ability to transfer load or customers onto other parts of the network. This scenario has become a common occurrence over the last 5 years and severely impacts the ability to perform planned maintenance activities in the northern suburbs. This has the secondary

effect of delaying other replacement and repair works in the northern suburbs, resulting in further deterioration of other assets in the area.

This program is estimated to cost \$7.1 million (\$2012/13) in the 2014-19 regulatory control period.

Failure to address this will mean reliability (particularly in the Darwin northern suburbs) will deteriorate and identified corrective maintenance savings of \$0.5 million will not be realised. Additionally, safety risks associated with these cables are not eliminated, placing the public at an elevated risk when digging near cables and during high voltage faults.

Oil Ring Main Unit Replacement Program (Sub8261)

The operation of aging Oil Ring Main Units presents a high risk to personnel and the public due to the consequences of a failure to anyone in the vicinity of the equipment. Many of Power Networks' Oil Ring Main Units are located in public areas such as lane ways, parks and road reserves.

There are 101 Oil Ring Main Units remaining in service on the regulated network and they are reaching end of life. Most units have been in service for greater than 30 years, and have an average age of 42 years.

This program is estimated to cost \$6.5 million (\$2012/13) in the 2014-19 regulatory control period.

Deferring this program of work only increases the safety risk to the public. Additionally, Oil Ring Main Units are maintenance intensive, requiring intrusive inspection and testing, which increases the risk of maintenance induced failures. In addition, failure to address this will mean that identified corrective maintenance savings of \$1.9 million will not be realised.

SCADA and Communications Replacement and Upgrade Program (Sub8257)

The SCADA & Communications assets comprising the SCADA Network and the Operational Telecommunications Networks consist of various asset classes. These asset classes include long life infrastructure, such as towers, equipment shelters and fibre optic cables, and shorter life assets, such as electronic equipment including remote terminal units, fibre optic terminals, microwave radio terminals, UHF two way radios, multiplexers, battery chargers, and other equipment such as batteries and antennas.

The Operational Telecommunications Network provides critical links for Protection, SCADA and other operational services such as the two way radio system. These systems allow System Control to efficiently conduct day to day switching of the network in a safe manner to permit Power Networks field staff to maintain and service the electrical network. The system visibility also allows appropriate actions to be taken by the system controllers at times of system faults or incidents, allowing for the isolation and location of faults and restoration of the network in a timely manner,

whilst also minimising the risk of significant system outages and ensuring the electrical assets are not significantly overloaded.

Based on the asset classes above, a replacement and upgrade program has been developed. This program is estimated to cost \$7.9 million (\$2012/13) in the 2014-19 regulatory control period.

This program is required to ensure the continued and reliable operation of these critical system assets.

Meters/Metering Program (Sub8276)

The Meters/Metering Program is required for the following metering programs:

- New meter installations;
- Meter replacements;
- Prepayment meter replacements; and
- Smart meter pilot.

New meters are required to meet the annual demand for new customer connections. The meter replacement program is required to replace meters due to age or condition. Meters have been selected for age replacement due to meter batches reaching the end of their economic life, based on manufacturers' specifications. Meter batches are selected for condition-based replacement for a variety of reasons, such as inaccurate recording of real or reactive power consumption.

There is a requirement to identify a replacement for the current electricity prepayment meters as the current meter vendor ceased the manufacture of that type of meter in June 2011. The current stock of prepayment meters is only expected to last for two more years and Power Networks propose to replace urban prepayment meters in the 2014-19 regulatory period.

Power Networks is planning a rollout of interval meters for customers using between 40 MWh and 750 MWh per annum, to enable the application of cost reflective network prices. This is expected to result in significant improvements for power factor and a slight reduction in future peak demand growth.

Reports by the Australian Energy Market Commission, the Productivity Commission, and the Australian Government's White Paper all propose reform of the distribution network, with emphasis on a range of reforms, including the roll out of smart meters.

Smart meters have already been rolled out in other parts of Australia. In this context, Power Networks proposes to undertake a smart meter pilot trial of 1,000 meters to test the costs and benefits associated with smart metering in the Northern Territory. This will be used to inform a potential large scale rollout of smart meters in future regulatory period(s) after the 2014-19 regulatory control period.

This program is estimated to cost \$10.9 million (\$2012/13) in the 2014-19 regulatory control period.

Distribution Transformers and Switchgear Program (Sub8273)

Distribution transformers and switchgear fail due to a variety of reasons, including age, poor condition and environmental issues, in particular, lightning strikes. Power Networks is required to hold transformer and switchgear stock such that if transformers or switchgear in the distribution network fail, they can be quickly replaced and customers restored to service.

The level of expenditure estimated going forward has taken into consideration that three suburbs have been converted from overhead to underground and that Power Networks will establish a targeted program of assessing transformer and switchgear condition and pro-actively replace equipment in poor condition prior to failure.

This program is estimated to cost \$5.8 million (\$2012/13) in the 2014-19 regulatory control period.

Underground Distribution Substation Replacement Program (Sub8258)

The condition of underground distribution substations, particularly in the Darwin region, is significantly affected by the high humidity and salty environment. Many of the units reaching an age of 35-40 years have significant corrosion resulting in oil leaks that are not economical to repair e.g. the back of the tank which is not accessible. High voltage switchgear used in these older substations is also difficult to maintain due to age, and provides limited or no protection to operators under fault conditions.

An oil sampling program on larger distribution substations (>1MVA) has also identified 10 units in the past two years that are in extremely poor condition. These vary in service life from 28 to 42 years' service life. The poor condition of units with lower service life can be attributed to either poor manufacture or high loading throughout their service life.

There are 1,600 distribution substations connected to the underground regulated network. In 2014/15 approximately 50 substations will exceed 40 years in service. By 2018/19, this will have more than tripled to 180.

This project is estimated to cost \$8.2 million (\$2012/13) in the 2014-19 regulatory control period.

It is expected that the rate of assets requiring replacement will increase at a faster rate in the 2019-24 regulatory control period. Proactively removing assets in the worst condition will lessen the cost impact maintenance in future periods and provide improved customer outcomes with a reduction in unplanned outages. In addition, failure to address this will mean that identified corrective maintenance savings of \$7.0 million will not be realised.

8.7 Forecast reliability and quality capital expenditure

Below is a brief outline of the material projects largely, or wholly, driven by the need to improve network reliability and quality of supply over the forthcoming regulatory control period.

Feeder Upgrade Program (Sub8262)

Each year Power Networks develops feeder performance reports for all poorly performing feeders. These reports include analysis of 5 years of historical outage data and interruption causes. The results of the analysis are targeted feeder upgrades planned for the coming financial year.

Typical works requested on the poorly performing feeders as a part of the feeder upgrade program include hardware upgrades, including the replacement of insulators, the installation of fibreglass cross arms and the installation of bat guards, network reconfigurations including recloser installations, and Air Break Switch to Gas Break Switch changeovers.

This program is estimated to cost \$7.7 million (\$2012/13) in the 2014-19 regulatory control period.

Rebuild the Channel Island Power Station to Hudson Creek 132kV Transmission Line – Elizabeth River Crossing (PRD30003)

The existing 132kV tower lines from Channel Island Power Station and the 66kV lines from Weddell Power Station to the Darwin area have been identified as structurally inadequate to withstand a Category 2/3 cyclone. If an event of this nature were to occur, the transmission lines would potentially suffer major damage that could take weeks to repair.

Works to strengthen the 66kV transmission system between Weddell and Darwin are planned for completion by October 2013. However, approximately half the Darwin-Katherine demand would remain at risk for the failure of the 132kV transmission system between Channel Island Power Station and Hudson Creek Terminal Station. In the event that the 132kV transmission circuits to Darwin were both damaged during a Category 2/3 cyclone, the economic impact on the Northern Territory would be substantial. It is therefore recommended to construct a section of new 132kV double circuit spanning the Elizabeth River.

This project is estimated to cost \$15.8 million (\$2012/13) with \$15.2 million (\$2012/13) expenditure in the 2014-19 regulatory control period.

8.8 Forecast compliance environment and safety related capital expenditure

All replacement projects, while not explicitly identified as compliance, environment and safety related capital expenditure, will result in significant less safety risk to the public and staff.

Modern equivalent equipment uses safer technology: indoor metal clad high voltage switchgear is arc-vented and very safe to be operated in front of the switchgear, outdoor oil filled 66kV current or voltage transformers are made with a soft polymer material that will tear rather than explode and eject debris, and 66kV indoor gas insulated switchgear equipment is fully enclosed with no oil.

Similarly, environmental standards will be greatly improved as zone substations are replaced. Currently, there are some power transformers that have no bunding capability, or the bunding does not meet current standards. All new zone substations will meet the highest environmental standards for oil containment.

8.9 Forecast non-network capital expenditure

There are two material non-network projects, as follows.

Capital Items and Essential Spares Program (Sub8255)

Power Networks is required to replace specialist test equipment and tools once they have reached end of life. Essential equipment spares are also required to ensure network operating equipment can be restored to service when parts fail or are identified during maintenance to be in a poor condition. Additional essential spares are needed to replace those consumed. As new equipment is brought into service, new essential spares will need to be purchased.

Post the 2008 Casuarina Zone Substation incident, it was determined that there were insufficient essential spares for Power Networks' in-service assets. Additionally, there has been a drive towards a condition-based approach to maintenance, requiring new testing equipment and the up skilling of staff. This resulted in a significant investment in both essential spares and capital items this regulatory control period. For the forthcoming 2014-19 regulatory control period, the expenditure for these categories will be significantly less as the backlog of urgent testing and remedial work is completed.

This program is estimated to cost \$6.0 million (\$2012/13) expenditure in the 2014-19 regulatory control period.

Metering IT Systems Upgrade (PRD30604)

Power Networks' metering IT systems are inadequate to support efficient metering service processes of a modern metering business operating in Australia.

An upgrade to the current Asset Management System, Maximo, is required to enable it to function as a metering register. In addition, the implementation of a Meter Data Management System, a Network Billing System and Revenue Assurance System is required to ensure meter data can be processed, validated, estimated, substituted, stored and billed accurately. A Prepayment Meter System is necessary to maintain continuity of prepayment metering capability given the impending obsolescence of the current platform.

This project is estimated to cost \$7.1 million (\$2012/13) with all expenditure in the 2014/19 regulatory control period.

8.10 Deliverability of proposed capital expenditure program

Over the last five years, Power Networks has substantially improved its capability in delivering a high level of capital project delivery. Additional resources as a result of the recommendations from Huegin Consulting in 2010 have substantially filled the gap internally to manage this high level of annual expenditure.³³ As stated in Section 2.6.1, Power Networks has introduced a number of strategies to ensure the organisation is capable of effective delivery of the capital program requirements. The most recent initiative, the Early Contractor Involvement (ECI) contract methodology for the design and construction of zone substations is already proving successful, with these projects tracking to program and within budget.

Table 18 below reflects the capital spend that Power Networks has achieved over the last four financial years. Last year's forecast spend of \$111.22 million is expected to be the highest Power Networks has ever spent and exceeds the estimated spend for every year of the forthcoming 2014-19 regulatory control period.

Table 18 – Historic capital expenditure (\$ million, nominal)

Financial Year	Actual/Forecast Expenditure
2009/10	\$85.02
2010/11	\$88.76
2011/12	\$78.77
2012/13 (F)	\$111.22

8.11 Demand management and non-network solutions

The Commission has acknowledged that the Rules provisions concerning the Regulatory Test version three and the Regulatory Investment Test for Distribution (RIT-D) are not appropriate for the circumstances in the Northern Territory³⁴. This is a decision that Power Networks supports.

Nevertheless, Power Networks considers that some aspects of the RIT are relevant to network investment. To this end, Power Networks has established a Demand Management Procedure that gives consideration to demand management and

³³ Due to the increased capital works program resulting from the Davies Review recommendations for Power Networks, Power and Water engaged Huegin Consulting in 2010 to determine the size of the workforce required to deliver the program of works and identify whether a 'gap' exists versus the current workforce.

³⁴ Utilities Commission, 2014-2019 Network Price Determination Framework and Approach Decision Paper, November 2012, p. 65.

non-network alternatives for individual material projects where appropriate³⁵. Power Networks Demand Management Procedure is included at Attachment 6.

The process involves the use of a screening test to determine whether demand management or non-network alternatives might be feasible and, if so, a process of consultation to develop such options with the assistance of external providers or internal resources. The process envisages the establishment of a panel of interested parties and providers that would be involved in the development of economic demand management and non-network options.

The expenditure on growth related material projects contained in this Proposal has been estimated on the basis of the most likely network reinforcement option. Where demand management or non-network alternatives may offer an economic solution in a particular case, this will be investigated in detail at the options evaluation stage and, potentially, developed as an alternative to avoid or defer reinforcement of the network.

8.12 Capital expenditure in the 2014-19 regulatory control period

The forecast of capital expenditure is included as Attachment 7. This is summarised in Table 19.

Table 19 – Capital expenditure (\$ million, real \$2013/14 and escalated)

Year	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Capital expenditure	\$84.74	\$74.80	\$57.44	\$48.39	\$57.58	\$322.96

This capital expenditure has been used in the NTRM to determine Power Networks' revenue requirement and prices described in chapter 15.

8.13 Prudence and efficiency of the capital expenditure forecast

The Commission has indicated its intention to use the provisions of Chapter 6 of the Rules, to the extent that they are compatible with the Northern Territory legislation and Code.

The provisions in the Rules relating to the prudence and efficiency of the capital expenditure forecast are set out in the boxed section at the start of this chapter. These provisions apply to the total of the capital expenditure forecast, which must meet the capital expenditure objectives and conform to the capital expenditure criteria.

Each material capital expenditure project and program, as defined in section 8.3.1 and described in sections 8.4 to 8.9 has been assessed against the Rules prudence and efficiency requirements. This assessment is contained in the analysis of each such project submitted as material accompanying this Proposal. These forecast

³⁵ Power Networks, Demand Management Procedure, June 2013.

capital expenditure justification documents are provided at Confidential Attachment 23.

8.13.1 Capital expenditure benchmarking

Power Networks faces a uniquely remote and harsh operating environment, which results in capital and operating cost inputs that exceed those of other Australian organisations. Appropriate allowance must be made for these differences in any benchmarking of costs with industry 'peers'.

Despite this difficulty of comparison, Power Networks has undertaken benchmarking of its capital costs during the current regulatory control period. Power Networks engaged SKM to provide equipment unit costs specific to the NT, and to prepare a comparison of these unit rates with other comparable Australian utilities (at Confidential Attachment 22).³⁶

SKM concluded that overall, Power Networks' unit rates are generally within 10-15% of unit rates applied to other utilities in recent valuations, and that in most cases the unit rates are higher than those used by other larger utilities and indicative of higher contract prices experienced by Power and Water, reflecting diseconomies of both scale and distance. Only in the case of one equipment category, power transformers, was Power and Water's cost less than other utilities. This reflects the favourable terms that Power and Water has negotiated with manufacturers in the most recent contract review, compounded by timing differences and exchange rate fluctuations between the arrangements of other utilities.

³⁶ Please note that this information was not used in the preparation of the capex forecast, as each material project and program is costed individually for labour, materials and equipment costs.

9 Capital contributions

Capital contributions play an important role in achieving efficient pricing for the network. The balance between the up-front costs of connection and the ongoing cost of network service is important in providing customers with price signals to appropriately influence their connection arrangements and subsequently, their consumption decisions. It is important also to preserve equity between new and existing customers.

Power Networks has refined the existing capital contributions arrangements with a view to providing more efficient price signalling. The proposed arrangements have been submitted to the Commission for approval and are included as Attachment 10. The existing policy documents are included as Attachment 8 and Attachment 9.

A feature of the proposed new capital contributions arrangement is the development of a customer refunds scheme, designed to improve the equity of existing arrangements, as capital contributions will be shared amongst subsequent Network Users who connect within five years to assets contributed by an original Network User.

This chapter of the Proposal outlines the existing capital contributions arrangements. It explains the reasons why Power Networks has proposed their revision and describes the changed arrangements.

Power Networks has forecast the capital contributions that will be made by customers during the 2014-19 regulatory control period, in cash and as contributed assets. The forecast contributions are taken into account in establishing Power and Water's proposed revenue, in chapter 15.

Code and Rule requirements

Clause 31 of the Code permits a network provider to recover capital contributions for the provision of connection equipment or system assets.

Capital contributions are distinguished from prudential requirements that may be required by a network provider to minimise the financial risks of investing in network assets.

Capital contributions arrangements must be in accordance with principles set out in Code clause 80. The most significant of these are:

- A capital contribution may only be recovered if the extension or development of the network would otherwise not be commercially viable over a reasonable period of time; and
- The capital contribution should be no more than that required to render the extension commercially viable;
- The Network User must make a capital contribution in accordance with the access agreement.

Clause 81 of the Code requires the network provider to provide the regulator with details of principles and methods for establishing capital contributions.

Rules clause 6.21.2 permits a DNSP to recover capital contributions, prepayments and financial guarantees for assets provided as part of a connection to the network. Under clause 6.21.2(b) the contributions, prepayments and guarantees may be up to the value of the future revenue related to the provision of direct control services for any new assets installed as part of a new connection or modification to an existing connection, including any augmentation to the distribution network.

9.1 Existing capital contributions policies

Capital contributions may apply to any new or upgraded Network Access Service sought by a Network User.

A capital contribution can be made by a network user in the form of:

- (a) An upfront financial payment to Power Networks, where Power Networks undertakes works required to provide new or upgraded Network Access Services to a Network User (ie. a cash contribution); or
- (b) The transfer of ownership of connection assets or network system assets to Power Networks from a Network User that has procured and funded the installation or construction of the assets by an Accredited Service Provider (ie. a gifted asset or in-kind contribution); or
- (c) A combination of (a) and (b).

Power Networks' existing capital contributions regime is set out in two complementary policy documents.

- The ***Distribution System Extension Policy*** (DSEP) covers extensions to unserved areas and the development of served lots. Mostly this is applied to small customers with an assumed typical consumption pattern and connection cost; and
- The ***2009 Capital Contributions Policy*** applies to the new or upgraded network connections of larger customers and generators.

These policy documents embody the principles established in the Code but differ in the detail of their implementation. An overview of these policies is provided in the following sections.

9.1.1 Distribution System Extension Policy

The DSEP sets out a range of standard charges for the development of served lots and for the extension of supply to currently unserved areas. These charges apply both to small customers and to developers.

A basic supply comprises 10 kVA single phase for domestic customers and 25 kVA three phase for commercial customers. There are additional charges for higher capacity supplies and for conversion to three phase supply.

In the case of unserved areas, there are charges for network extensions along public roads and per-lot connection charges. Under the policy, reticulation installed within developments is gifted to Power Networks.

9.1.2 2009 Network Capital Contributions Policy

The 2009 Networks Capital Contributions Policy applies to larger customers (with annual consumption of 750MWh or more). It has as its basis a contribution calculated from the following equation:

$$\text{Capital contribution} = \text{PV (actual and attributed costs of connection)} \text{ less } \text{PV (customer tariff} \times \text{volume)}$$

where:

- (a) the “actual and attributed costs of connection” includes the capital cost of connection assets and network system assets attributed to the customer, including the advancement of system costs outside the planning horizon.
- (b) the “customer tariff×volume” term is the incremental revenue derived from the new or altered customer connection.
- (c) the PV (present value) calculation uses Power Networks’ regulated rate of return and is for a period of 30 years for residential customers and 15 years for other customers, unless a shorter period is nominated by Power Networks.

9.2 Proposed 2014 Network Capital Contributions Policy

Power and Water has submitted a proposed revised Networks Capital Contributions Policy, and has sought the Utilities Commission’s approval to replace the two existing policies with this proposed revision.

Power Networks has experienced a number of instances where extension of the network to outer suburban areas has resulted in charges to developers under the DSEP policy that fall well short of funding the lengthy network extensions involved. Similarly, there have been a number of instances where upgrades to serviced lots have resulted in charges to developers under the DSEP policy that fall well short of the actual funding required for the upgrades.

Power Networks proposes changes to the existing capital contributions regime to:

- More closely reflect the cost of connection to the electricity network for any new or upgraded Network User;
- Ensure the commercial viability of connections made to the electricity network;
- Ensure more equitable outcomes for both new and existing Network Users; and
- Simplify the framework and make the capital contributions process more efficient and simpler for Network Users and developers to follow.

The proposed policy contains a greater level of detail, to clarify Network Users’ contribution requirements towards augmentation of the upstream network. The

proposed policy will achieve closer alignment with the policies and practices currently in place in other jurisdictions.

9.2.1 2014 Networks Capital Contributions Policy

The simplified arrangements for calculating Network Capital Contributions follow the same principles as the existing policies (as required by the Code) but differ in detail, according to the class of connection to the network. These arrangements are summarised in Table 20.

Table 20 – Summary of revised capital contributions arrangements

Class of network connection	Funding of dedicated Connection Assets	Funding of augmentation of Upstream Shared Assets
1. Developer of a subdivision or multi residence building	Developer to contribute all costs associated with assets downstream of the connection point to the shared network	Funded by Power and Water A prudential guarantee of tariff revenue may be sought
2. Large Individual Network User	Network User to contribute: PV (dedicated Connection Asset cost) <i>plus</i> PV (proportion of cost to augment Upstream Shared Assets) <i>less</i> PV (expected tariff revenue <i>less</i> shared network costs) A prudential guarantee of tariff revenue may also be sought	
3. Small Individual Network User		
4. Generation Network User	Network User to contribute cost of dedicated Connection Assets	Network User to contribute cost of augmenting Upstream Shared Assets (may be proportionately funded by Power Networks)

Some other aspects of the proposed 2014 Network Capital Contributions Policy (NCCP) that have been changed are:

- The adoption of a standard investment timeframe of 15 years for all Network Users, unless a shorter time frame is determined by Power Networks for connections with a short life or high risk of stranding;
- Default residential and commercial consumption and demand profiles will be developed annually by Power Networks, based on the average Northern Territory residential and commercial consumption and demand from the previous financial year;
- The “shared network costs” is the attribution of incremental network tariff revenue from the Network User to the costs of the existing shared network, calculated as 50 per cent of the PV of “expected revenue”.

A Capital Contribution will only be levied if the outcome of the application of the above formula is a positive value (i.e. where a revenue shortfall is expected). In such a case, the value of the contribution charged will not exceed this amount.

A new feature of the proposed NCCP is the introduction of a cost sharing scheme, whereby capital contributions will be shared amongst subsequent Network Users who

connect within five years to assets contributed by an original Network User. A subsequent Network User is required to make a proportionate capital contribution to the assets, which is reimbursed to the original Network User. There are some restrictions to this arrangement, as explained in the Policy. The cost sharing arrangement is limited to a single “branch” of the network and does not extend to developers or to a large Network User (with annual consumption 750 MWh or more) where a small Network User subsequently connects to the contributed assets.

9.3 Forecast capital contributions

The capital contributions forecast has been based on the actual level of contributions received by Power Networks in the current regulatory control period after the removal of one-off cash contributions from large customers to derive the underlying level of contributions.

Power Networks’ capital forecast for the 2014-19 regulatory control period has been developed based on the assumption that the revised NCCP will be approved for an implementation date of 1 July 2014.

The proposed change to the NCCP will affect the level of contributions from 2014/15. The major assumptions underlying the contributions forecast are as follows:

- There are no confirmed large developments in Power Networks’ planning horizon that will result in significant customer contributions, and therefore none have been included in the contributions forecast.
- A step change (increase) in cash contributions from small network users is forecast in 2014/15 as small network users whose connections are currently funded by Power Networks will be required to pay more cost reflective capital contributions. (Note that this amount takes into account an estimate of projected future tariff revenues, offset by shared network costs as per the proposed capital contributions calculation in the revised NCCP).
- Gifted assets are forecast to increase in 2014/15, as developers who currently pay DSEP charges will contribute all costs associated with assets downstream of the connection point to the shared network under the revised NCCP. Developers will construct and gift these assets to Power Networks under the revised NCCP.
- The increase in cash contributions and gifted assets has been derived by calculating the amount that Power Networks has under-recovered under DSEP in 2012/13 from small individual network uses and developers.
- There is no allowance to recover opex under existing NCCP and DSEP, and none is forecast under the revised NCCP (the revised NCCP provides for the recovery of incremental opex only if significant and not funded as part of the regulatory determination).
- With the exception of 2014/15, where a step change has been forecast, contributions from small individual Network Users have been forecast to grow in line with new connections (assumed baseline growth rate of 2.7 per cent).

Other contributions are expected to remain constant, as no prospective major developments are confirmed for the forecast period.

The actual and estimated level of capital contributions for the 2009-14 regulatory control period are set out in Table 21.

Table 21 – Capital contributions during the 2009-14 regulatory control period (\$'000, nominal)

Capital Contributions	2009/10	2010/11	2011/12	2012/13	2013/14
Cash contributions	8,232	1,166	3,975	7,516	2,109
Contributed assets	2,645	6,141	7,143	7,336	7,534
Total capital contributions	10,877	7,307	11,118	14,852	9,643

With regard to the above considerations, the forecast capital contributions for the 2014-19 regulatory control period are shown in Table 22.

Table 22 – Capital contributions forecast (\$'000, real \$2013/14)

Capital Contributions	2014/15	2015/16	2016/17	2017/18	2018/19
Cash contributions	2,615	2,648	2,682	2,717	2,753
Contributed assets	9,234	9,484	9,740	10,003	10,273
Total capital contributions	11,849	12,131	12,421	12,719	13,025

10 Forecast operating and maintenance expenditure

This chapter of the Proposal details Power Networks' operating and maintenance expenditure (opex) forecast for the provision of standard control services in the 2014-19 regulatory control period³⁷.

Power Networks considers that this expenditure is required to meet the Code requirements and the capital expenditure objectives described within the Rules. This chapter includes:

- A summary of the relevant Code and Rule requirements;
- A review of the opex that Power Networks is forecast to incur in the 2014-19 regulatory control period;
- A description of the process by which the opex forecast for the 2014-19 regulatory control period has been developed;
- A description of the inputs to the opex development process including benchmarking and the asset management approach;

Code and Rule requirements

The Code does not specifically identify the requirements for the operating expenditure forecast used to determine network revenues. The Code sets out the high level objectives of price regulation, including in clause 63(a) achieving the efficient costs of supply. Clause 68(a) requires the regulator to take into account the demand growth that the network provider is expected to service.

Section 6.5.6(a) of the Rules requires that Power Networks submit a forecast of operating expenditure to meet the operating expenditure objectives over the relevant regulatory period, being to:

1. Meet or manage the expected demand for standard control services over that period;
2. Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;
3. Maintain the quality, reliability and security of supply of standard control services; and
4. Maintain the reliability, safety and security of the distribution system through the supply of standard control services.

Further, section 6.5.6(c) of the Rules requires the AER to accept Power Networks' proposed operating expenditure if it reasonably reflects:

1. The efficient costs of achieving the operating expenditure objectives;
2. The costs that a prudent operator in Power Networks' circumstances would require to achieve the operating expenditure objectives; and
3. A realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

These are referred to as the operating expenditure criteria.

³⁷ There are two components to opex that are subject to separate consideration: operating expenditure and maintenance expenditure.

- The forecast opex for the 2014-19 regulatory control period associated with key categories of expenditure, being:

Operating expenditure	Maintenance expenditure
Network Management	Preventative Maintenance
Service Delivery	Planned Corrective Maintenance
Strategy and Planning	Unplanned Corrective Maintenance
Metering	Specific Maintenance
Regulatory Costs	-
GSL Costs	-
System Operations	-
Corporate and Shared Services	-
Other	-

- Discussion, within each of the expenditure categories described above, of:
 - Variances from the 2013/14 base year and the associated drivers of those variances;
 - The approach undertaken to ensure the development of a prudent and efficient forecast; and
 - The approach undertaken to ensure the efficient costing of the forecast.
- Assurance that the forecast operating and maintenance expenditure programs can be delivered.

Power Networks considers that the proposed levels of expenditure described in this chapter meet the operating expenditure criteria, and should therefore be accepted as part of the Commission's determination.

10.1 Framework and Approach Decision

In its Framework and Approach Decision Paper, the Commission confirmed its intention to assess the prudence and efficiency of Power Networks' operating and maintenance expenditure forecasts in accordance with clause 6.5.6 of the Rules. That is, the total of the expenditure forecast would be assessed against the operating expenditure objectives and accepted by the Commission if the forecast meets the operating expenditure criteria.

10.2 Operating and maintenance expenditure in the 2009-14 regulatory control period

Power Networks' overall operational expenditure profile over the past five years, shown in Table 23, has been mainly driven by the deteriorating state of assets, changes to the asset management approach, and the minimum levels of expenditure

required to satisfy core network asset management related principles regarding the safety of the network and the objective maintenance needs of assets.

Table 23 – Operating and maintenance expenditure 2009-14 (\$ million, nominal)

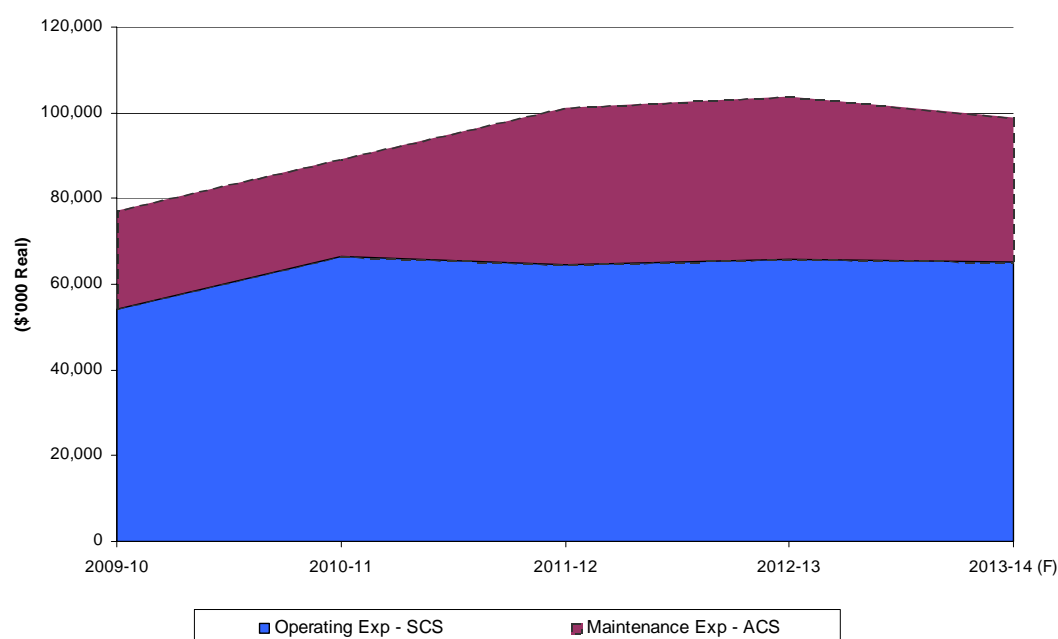
Year	2009/10	2010/11	2011/12	2012/13	2013/14 (F)
Actual Operating expenditure	\$48.43	\$61.35	\$60.91	\$63.39	\$64.52
Actual Maintenance expenditure	\$20.47	\$20.94	\$34.51	\$36.63	\$33.27
Actual O&M expenditure	\$68.91	\$82.29	\$95.41	\$100.02	\$97.79

Power Networks' overall operational expenditure increased between 2009/10 and 2011/12 as the level of preventative maintenance expenditure increased having gained a better understanding of asset condition. This also drove an increase in network operating costs as new expertise, skills and resources required to transform the asset management function were developed.

With the implementation of a new asset management system, and the changes to asset management policies, practices and procedures, Power Networks has moved from a state of little knowledge about the condition of network assets to one where Power Networks is now increasingly able to efficiently manage them by trading off preventative maintenance, corrective planned maintenance, corrective unplanned maintenance and replacement expenditure in a least cost optimised manner.

This evolution is visible in Power Networks' operating and maintenance expenditure patterns over the last five years displayed in Figure 15. Activities contributing to and being driven by increasing knowledge about network assets is reflected in the rising maintenance expenditure from 2011/12 onwards.

Figure 15 – Power Networks' opex in the 2009-14 regulatory control period (\$'000, real)



Although Power Networks' 2010/11 operating³⁸ and maintenance³⁹ expenditure was benchmarked by Huegin as being in the middle of Australian distribution networks, operating efficiency could be improved if adequate regulatory funding was provided to address a number of funding related efficiency gaps that have been identified.

The shortfall in 2009-14 regulatory funding allowance has resulted in gaps in Power Networks' current operational and investment expenditure. This is in turn leading to the rationing of some standard control services and support functions and driving up costs above efficient levels. Examples of regulated funding constraints driving inefficient expenditure include:

- Under-expenditure on replacement investment is increasing the cost of planned and unplanned corrective maintenance (fault management); and
- Under-expenditure on planned corrective maintenance is leading to a growing backlog of corrective maintenance, which is in turn driving an increase in unplanned corrective costs above efficient levels.

In addition to the degraded level of operational efficiency, underfunding is reducing the scope and quality of standard control services.

In summary, Power Networks believes the 2013/14 operational expenditure reflects a reasonable and improving degree of efficiency given the level of regulated funding and need to ensure equipment operates safely and the maintenance of assets is based on their objective need.

The asset management and financial systems Power Networks uses to ensure the ongoing efficiency, prudence and reliability of operational expenditure and the results of recent independent reviews by industry experts to verify and validate them are outlined in the following sections.

10.3 Efficiency of the operational expenditure base year

Power Networks has selected 2013/14 as the base year for its top-down operational expenditure forecasts, which use the base, step and trend modelling approach.

The following sections outline the benchmarking Power Networks' has undertaken to ensure the base year is an efficient starting point upon which to base an efficient operational expenditure forecast as required under the Code and Rules.

10.3.1 Efficiency Benchmarking

As part of its preparation for the 2014 Network Pricing Determination, Power Networks sought to test whether it was delivering outputs in a reasonably efficient manner given its relatively unique operational circumstances as having the fewest

³⁸ Huegin Consulting, 2012 Distribution Benchmarking Study, p.80 (provided at Confidential Attachment 25).

³⁹ Ibid, p. 68.

regulated electricity network customers and the second lowest network territory and customer density in Australia.

Two major exercises have been undertaken in this regard. The first is the Huegin Consulting electricity distribution benchmarking study completed in 2012 covering the full range of network capex and opex categories however focusing on a few key categories.⁴⁰ The second study was by Energeia, which focused on the full range of metering capex and opex relative to the market. Table 24 demonstrates the standard control services that each review benchmarked.

Table 24 – Standard Control Services benchmarked

Standard control service	Supporting service	Type	Huegin (2012)	Energeia (2013)
Network Services	Construction	Capex	X	
	Maintenance	Opex	X	
	Operations	Opex	X	
	Planning	Mix	X	
	Designing	Capex	X	
	Emergency response	Opex	X	
	Administrative support	Mix	X	
Connection Services	Connection of connection assets	Capex	X	
	Small service connection	Capex	X	
	Installation inspection	Opex		
	Operating and maintaining connection assets	Opex		
Metering Services	Meter installations	Capex		X
	Scheduled and unscheduled meter reading	Opex	X	X
	Management of meter data	Opex		X
	Disconnection and reconnection	Opex		X
	Investigations and testing	Opex		X
	Maintenance and repair	Opex		X

10.3.2 Huegin (2012)⁴¹

Power Networks participated in the Huegin benchmarking project involving eight electricity distribution networks from across Australia and one from New Zealand. This study, which was undertaken in 2012, found Power Networks' operating costs were comparable to industry peers using imperfect but typical metrics. Given Power Networks' higher operating input costs, lower economies of customer density and

⁴⁰ Huegin analysed cost data from the FY08 to FY11 period.

⁴¹ Huegin Consulting, 2012 Distribution Benchmarking Report.

scale, this is a reasonable result. The study is provided at Confidential Attachment 25.

Unlike many studies of its kind, the Huegin report takes great pains to identify the key contextual factors that impact on management's ability to deliver lower cost outcomes. These factors, if not properly considered in the approach, can lead to misleading conclusions about relative efficiency. As highlighted in the report, Power Networks' unique operating environment makes it very difficult to benchmark correctly.

Nevertheless, the key findings of the benchmarking study (underlining added for emphasis) are:⁴²

- Power Networks' remote location and small scale drive higher costs in several areas compared to eastern seaboard distributors that operating in the National Electricity Market (NEM).
- A key driver of costs (and cost differences across businesses) was found to be the network design – in terms of the proportion of underground network and voltage levels of assets. Power Networks has a high (and increasing) proportion of the network underground and the highest percentage of underground assets above 66kV of all benchmarking participants.
- In terms of the two major capital expenditure categories (replacement and growth) Power Networks has:
 - Relatively low replacement capex, reflective of its young asset age and low rate of defects.
 - Relatively high growth capex, driven by increases in peak demand above the average rate experienced in the NEM and the increasing rate of underground asset installation.
- Power and Networks' maintenance costs are at the benchmark level when normalised for network density.
- The unique nature of Power Networks' business compared to the NEM businesses drives an apparently higher network operations cost when measured per customer (Power Networks has a low population, but high customer usage); when measured per kilometre, Power Networks' [network operations] costs are close to the median.
- The Service Level Agreement that Power Networks has with Power and Water Retail provides for much lower customer service costs than the NEM businesses.
- Meter reading costs per customer are at the median level.
- Power Networks' support costs (vehicles and property in particular) are lower than most of the other participants – this observation was common for the multi-utility businesses in the group.

42 Huegin Consulting, 2012 Distribution Benchmarking Study, page ii.

- Power Networks' workforce costs, despite rising the most over the four years, remain amongst the lowest in the group despite the remote location and constrained labour market.

Based on the above findings, Power Networks believes that the base year operational expenditure is at a reasonably efficient level given the circumstances. The findings of the study also affirm the effectiveness of Power Networks' operational efficiency management systems and strategies implemented over the past few years.

10.3.3 Energeia (2013)

Following on from the recommendations of the independent expert review of the metering services section, Power Networks engaged Energeia to determine the most efficient operating model and operational expenditure profile. This involved benchmarking market and investment alternatives against internally provided services.

Energeia engaged with five AEMO accredited meter and data providers, two of which were interested in providing a quote. The change in governments in Queensland and New South Wales has impacted the government owned accredited metering service providers in those two states. Quotes were obtained from one utility provider in another state, and one national field services provider.

Energeia's investigation found that Power Networks' existing mix of internal and external services were the most efficient possible, given market provided prices and expected levels of customer demand⁴³. Services without an outsourced rate could not be benchmarked due to a lack of market interest in supplying them.

A number of functions were identified as not currently being provided by Power Networks, such as meter compliance and maintenance, due to lack of available funding. Energeia also estimated that each could also be provided internally at a lower cost than an external provider, except in the case of National Association of Testing Authorities (NATA) accreditation. NATA accreditation represents a significant additional fixed cost overhead, which Energeia recommended outsourcing.

Energeia noted in its recommendation that even though some services may appear cost effective to outsource on a stand-alone basis, it did not make sense to do so if they could not be delivered remotely because of the minimum setup cost required to establish and maintain the service in the Northern Territory. This mainly impacts meter provision related services involving field services resources.

10.4 Operating expenditure development process

In the development of the operating expenditure forecast, individual opex categories have been considered on a top-down basis using the base, step and trend modelling

⁴³ The main outsourced standard control service is manual meter reading.

approach preferred by the AER, and have been based on the 2013/14 Statement of Corporate Intent (SCI) forecast.

The operating expenditure is considered in the following individual opex activity categories:

- Network Management;
- Service Delivery;
- Strategy and Planning;
- Metering;
- Regulatory Costs;
- GSL Costs;
- System Operations;
- Corporate and shared services; and
- Other costs.

Each of these categories are summarised below.

As part of Power Networks operating expenditure governance process, each of the forecasts has been individually justified as prudent and efficient and approved by Senior Management. These forecast operating expenditure justification documents are provided at Confidential Attachment 24.

10.4.1 Network Management Opex

This forecast seeks to continue provision of centralised Network Management services to the Networks business. Those services include:

- General management and coordination of the Power Networks' group activities and performance against established objectives;
- Management of health and safety legislative requirements and procedures;
- Management of environmental legislative requirements and procedures;
- Management of organisational change within Power Networks to improve its performance; and
- Management of the Power Networks' financial and regulatory reporting.

No step changes or one-off costs have been included in this forecast.

10.4.2 Service Delivery Opex

The Service Delivery group, headed up by the Group Manager Service Delivery, is responsible for the delivery of Power Networks' maintenance and various capital work programs. It is composed of the following sections: Field Services, Test and Protection Services, Substation Services, SCADA and Communication Services, Work Practices and Training, Metering Services, and Project and Finance Administration.

Note that the direct costs associated with the Metering function are considered separately and not included in the Service Delivery opex forecast.

The Service Delivery opex forecast includes a step change relating to an additional six FTEs (Trade Technical positions) in the Field Services section. The need for these six additional positions is driven by an increase in the cable replacement, cable condition assessment and underground distribution substation replacement work programs in the forthcoming 2014-19 regulatory control period. In addition, it is also driven by an increase in the underground proportion of the regulated network. Currently, approximately 60 percent of the Darwin network is underground, with that proportion forecast to increase as new developments, which will be fed by an underground network, come on line. This will result in increasing maintenance requirements for the underground network.

It is proposed that 35 per cent of the total cost of these internal resources be recovered through the Service Delivery opex forecast in Power Networks' operating expenditure proposal. The remaining 65 per cent will be recovered through Power Networks' capital and maintenance expenditure proposals.

In addition, there is also a step change for an additional FTE (science & engineering professional position) in the SCADA and Communications Services section. This position is required to operate and maintain the IDMS.

The Service Delivery opex forecast also includes some other immaterial step changes relating to new licence costs and support for the IDMS, and upgrades to the Energy Management System, Microwave Radio System and UHF Radio System.

10.4.3 Strategy and Planning Opex

The Strategy and Planning group, headed up by the Group Manager Strategy and Planning, is responsible for Power Networks' strategy and planning functions, including asset management, network planning development, and investment analysis. It is also substantially responsible for the delivery of the major capital program. It is composed of the following sections: Asset Management, Network Development and Planning, Network Engineering, Contracts and Projects, and Project and Finance Administration.

The step changes that have been included in the Strategy and Planning Opex forecast include an allowance for mobile devices to provide maintainers with the ability to efficiently perform data entry in the field, a Customer Administration Officer (0.5 FTE), and a Customer Connections Administration Officer (1 FTE).

The Customer Administration Officer (0.5 FTE) will be responsible for the implementation of the Networks Capital Contribution Policy, and in particular Power Networks' main point of contact for Developers, and managing service order requests for second tier retailers.

The Customer Connections Administration Officer (1 FTE) will be responsible for administration of Power Networks' Customer Connection enquiries and applications to

meet the requirements of the Electricity Networks (Third Party Access) Code, the Electricity Retail Supply Code, the Network Technical Code, the Networks Capital Contributions Policy, and the Electricity Standards of Service Code. In addition, the position will be responsible for the administration of enquiries and applications for the connection of solar PV and other small generators, to meet the requirements of the Network Technical Code.

10.4.4 Metering Opex

Power and Water Corporation's Power Networks' Metering Services group supplies electricity metering provision, and electricity and water meter data services. Expenditure on water meter data services is incurred by Power and Water's Water Services business unit, and has been excluded from this Proposal.

The Metering opex forecast is required to supply the required level of metering services to Power Networks, to enable compliance with regulatory and statutory obligations. The forecast includes the following step changes to expenditure:

- The support and licensing costs associated with the proposed upgrade to metering IT systems;
- The support costs associated with the rollout of interval meters to customers consuming 40-750MWh per annum and an interval meter trial to customers consuming 15-40MWh per annum;
- The support costs associated with the replacement of prepayment meters; and
- An increase in Power Networks Metering Services' workforce. Eleven additional positions are required to bring Metering Services up to the standard of a modern metering business. The number of existing and additional metering staff was recommended in an independent review by Phacelift consultants conducted in 2012.

10.4.5 Regulatory Costs Opex

The Regulatory Costs forecast includes a requirement for additional expenditure to adequately comply with existing and new regulatory obligations under the Rules framework. Two additional full-time resources are required to manage regulatory compliance (a Regulatory Compliance Manager and a Regulatory Reporting Officer).

The Commission is progressively moving from the established arrangements to the Rules regulatory framework, to the extent that this is compatible with the Northern Territory legislation. The Rules framework imposes significant additional regulatory reporting burdens upon Power Networks, both on an ongoing reporting basis and in preparing for the regulatory determinations, at five-yearly intervals.

The Regulatory Costs forecast also includes the estimated cost of preparing for the 2019 Networks Price Determination.

10.4.6 GSL Costs Opex

A Guaranteed Service Level (GSL) Code was released by the Commission on 23 December 2011 prescribing the implementation of a GSL scheme from 1 January 2012, with full implementation from 1 July 2012.

The GSL scheme applies to those customers using less than 160 MWh per annum (mainly households and small businesses), located in the three regulated electricity systems of Darwin-Katherine, Alice Springs and Tennant Creek. It applies to network services and includes network reliability performance and network related customer service measures.

The GSL Costs Opex forecast has two components:

- GSL Payments – forecast GSL payments to customers; and
- GSL Operating Costs - relating to the on-going administration, reporting and customer interaction associated with the GSL Scheme.

The base year GSL payment estimate is sourced from the PricewaterhouseCoopers (PwC) GSL Scheme Costing Report. This estimate is based on best case compliance assumptions. Power and Water engaged independent consultants PwC to prepare estimates of the potential GSL payments by performance measure using annual estimates of the transaction volumes associated with each GSL measure. GSL payments are assumed to decrease in line with capital expenditure on the GSL Program (part of Power Networks' Feeder Upgrade Program).

GSL operating costs relate to the on-going administration, reporting and customer interaction associated with the GSL Scheme, and include the following activities:

- Assessment of eligibility for GSL payments;
- Processing GSL application forms;
- Organising GSL payments for eligible customers;
- Recording of monthly payments made to customers; and
- Annual updates of GSL feeder maps for Power and Water's website (requirement of the GSL Code).

The GSL costs forecast includes a step change from 2014/15 for half of an additional resource within Power Networks, which is required to administer the GSL Scheme on an on-going basis, as recommended by PricewaterhouseCoopers in its Guaranteed Service Level Scheme Implementation Final Report.

10.4.7 System Operations Opex

This program seeks to continue the provision of System Operations services to the Networks business. Those services are the subject of a Service Level Agreement

(SLA) between the Power Networks and System Control business units (provided at Confidential Attachment 26). The main services currently provided by System Control to Power Networks include:

- **Network operations:** principally the control of the transmission and HV distribution systems within the capability established by Power Networks;
- **Under Frequency load shed:** design and settings to maintain the secure operation of the system in response to transmission and generation contingencies;
- **Access to infrastructure:** prepare and coordinate switching and provide access, to enable safe working on the system by Power Networks staff. This includes providing access to confined spaces; and
- **Fault call centre services:** for the public, on a 24 hour basis.

In addition to the above, System Control maintains the call-out roster and is responsible for crew dispatch and logging and the provision of a range of miscellaneous information to Power Networks.

10.4.8 Corporate and Shared Services Opex

The Corporate and Shared Services opex is required to support Power Networks operations, and includes the estimated cost of corporate overheads, and the estimated cost of the provision of shared call centre services by Power and Water Retail to Power Networks.

Power and Water is a multi-utility that provides electricity, water and waste water services to the main population centres of the Northern Territory and to 72 remote communities.

Power and Water's owners and management have established an organisational structure that helps deliver efficient costs through the sharing of common overheads among multiple utility service streams.

Regulated network businesses in Australia all have certain fixed operating costs due to the range of standard control services that must be provided to each customer, regardless of the number of customers.

Power and Water's regulated network has the lowest number of customers in Australia, scattered across a territory that is the second largest in Australia. This substantial diseconomy of scale is only partially compensated for by economies of scope, through Power and Water's multi-utility organisational structure.

The multi-utility model is a common international approach to achieving economies of scale and scope, particularly among local or municipal utility service providers.

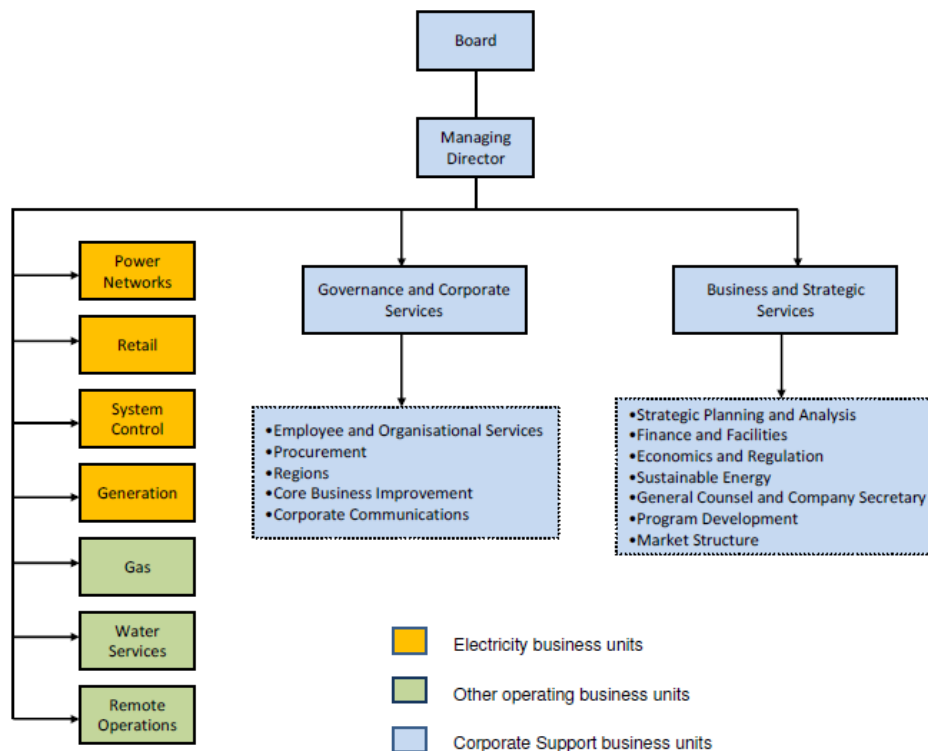
In Power and Water's circumstances, adoption of a multi-utility structure enables the sharing of common corporate costs associated with executive management, IT, legal, procurement, etc. overheads, and other shared service costs such as call centre costs, among the electricity, water and sewerage operating businesses.

Corporate Overheads

Power and Water's executive structure comprises operating business units and corporate services divisions (including the Managing Director's office). The costs of the corporate support business units are recovered from the operating business units.

The current Power and Water executive organisational structure is shown in Figure 16.

Figure 16 – Power and Water's current executive organisational structure



Cost Allocation Method

Power and Water's corporate overheads allocation methodology is outlined in the Power Networks' Cost Allocation Method (CAM), provided at Attachment 13 (public version) and Confidential Attachment 28.

Wherever feasible, Power and Water assigns the direct cost of services where they are provided between its business units. The costs so assigned may include a proportionate allocation of the corporate service costs, based on the value of the service and the budgeted expenditure of the business unit providing the service.

Where costs are allocated between business units, a causal basis has been chosen using the most appropriate allocator for the service concerned. In forming a judgement on an appropriate cost driver, the costs are allocated in a manner that:

- Is fair and reasonable;

- Ensures the substance of the underlying transactions and events are reported; and
- Is capable of certification by an auditor.

If a driver cannot be readily measured and applied without undue cost and effort, an alternative causal cost driver is identified. Where no causal relationship can be established without undue cost and effort, cost may be allocated on a non-causal basis.

Immaterial items where a causal relationship cannot be established without undue cost and effort may be allocated on a non-causal basis. The aggregate of all items subject to all non-causal bases of allocation must not have a material effect on the statements or reports.

Those causal allocators used in relation to Power Networks include the following:

- Equal shares, where a service would otherwise need to be separately provided by a number of business units;
- A share based upon employee or user numbers, where the level of a service is proportionate to the number of personnel;
- A share based upon budgeted expenditure or asset values, where overall costs are proportionate to those amounts; and
- A share based upon historic records of the frequency of events and their average cost, such as with call centre and system control costs.

Shared Services

Power and Water Retail provides call centre services to Power Networks (and the other operating business units) during normal hours, for network faults and emergencies.

For Power Networks to establish its own call centre for network matters or its own operational group would involve a significant level of duplication and additional cost that would ultimately be borne by electricity consumers. The arrangements that have been established are not dissimilar to those in place elsewhere in Australia.

The provision of call centre services by Power and Water Retail to Power Networks is covered under a Service Level Agreement (SLA) for the provision of specified retail services (provided at Confidential Attachment 27).

10.4.9 Insurance provisions

Power and Water carries external insurance cover for Power Networks' substations. This cost is factored into the corporate cost allocations.

However, Power Networks is also exposed to damage to the "poles and wires" component of its network assets taking place due to events such as cyclones and floods. Insurance against such events is very difficult to obtain at reasonable cost.

Power Networks expects that the force majeure pass through provision would cover such events, to the extent that the associated expenditure exceeded the materiality threshold of 1 per cent of Power Networks' annual revenue⁴⁴. However, there has been a history of damage to the network due to cyclones that in most cases is less than this threshold level. Indeed, there is likely to be a significant event on average at three to five year intervals and a risk of this nature is more appropriately managed with a self-insurance allowance.

Power Networks has therefore established a self-insurance allowance to cover expenditure on storm and flood events to the "poles and wires", with a claim limit of \$2.5 million, in the vicinity of the pass through materiality threshold. This self-insurance allowance has a minimum claim (deductible) limit of \$50,000.

A record will be maintained that will allow Power Networks to report, on an annual basis, monies set aside, actual expenditure incurred and the outstanding balance of the revenue collected for self-insurance purposes. Power and Water does not intend to physically set the money aside as restricted funds, as it has determined that this is not an effective use of the Corporation's working capital. However, Power and Water will perform an annual assessment to ensure the committed funds are available for their intended use in the future.

In establishing this self-insurance allowance, Power Networks has sought advice from Aon Global Risk Consulting on the structure of the arrangement and to provide an actuarial assessment of the risk and required level of the provision. Aon's report is included as Confidential Attachment 30 and Confidential Attachment 31. As recommended by Aon, Power Networks will record annually the charge collected for this self-insurance arrangement and proposes that this be included as an operating expense in the 2014-19 regulatory control period.

10.4.10 Forecast operating expenditure

The forecast operating expenditure for the 2014-19 regulatory control period arising from the programs of work described in this section 10.4 is shown in Table 25.

Table 25 – Operating expenditure (\$ million, real \$2013/14 and escalated)

Year	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Operating expenditure	\$68.71	\$67.75	\$66.03	\$67.22	\$66.68	\$336.39

10.5 Maintenance expenditure development process

Maintenance expenditure has been forecast using a "bottom up" approach. The use of historical trends in overall expenditure was not considered appropriate, due to significant changes in cost recording methodologies during the current regulatory

⁴⁴ Utilities Commission, 2014-2019 Network Price Determination Framework and Approach Decision Paper, November 2012, p. 81.

control period. In addition, historical expenditure trends are not necessarily a good indication of future maintenance requirements.

The maintenance expenditure is considered in four distinct categories of material projects or programs:

- Preventative Maintenance;
- Planned Corrective Maintenance;
- Unplanned Corrective Maintenance; and
- Specific Maintenance.

Expenditure in each of these categories was analysed for the following asset classifications:

- Terminal & Zone Substations;
- Transmission & Distribution;
- SCADA & Controls;
- Decommissioned Assets;
- Vegetation Management; and
- Metering.

10.5.1 Preventative Maintenance

The preventative maintenance expenditure forecast is based on maintenance schedules extracted from the Asset Management System (Maximo) for the period 2014/15 to 2018/19. The resulting forecast was then adjusted based on:

- Step changes to the asset base. In particular, new and replacement zone substations, asset replacement programs and other augmentation projects due to growth;
- Estimated costs of new preventative maintenance activities that will be implemented in 2014/15 to address known asset reliability issues;
- A reasonable allowance for travel time and associated travel expenses incurred by maintainers travelling to remote locations; and
- An estimate for non-trades labour costs related to the planning, supervision and administration of the maintenance programs (i.e. planners, supervisors, administration staff, and asset managers).

Vegetation management is planned and managed through period contracts. Expenditure forecasts are based on historical expenditure and associated reliability trends due to vegetation related outages, and improvements required to meet reliability targets and improve the resilience of the network during intense storms, rainfall and cyclones.

10.5.2 Planned and Unplanned Corrective Maintenance

The planned and unplanned corrective maintenance expenditure forecasts were developed using a modelling process with the following steps.

1. The baseline expenditure year 2012/13 was examined in detail and revised to correct for any inconsistencies in cost allocations between planned and unplanned corrective. This analysis formed the baseline in the forecast model.
2. The above costs were then split by asset classifications detailed in Section 10.5, and further split into lower level asset classes where necessary for the application of step changes, particularly for transmission and distribution asset classes. This was also used to derive a baseline volume of corrective work for each asset class.
3. Expenditure was forecast based on the calculated “defect growth” rate for the relevant asset classes. The defect rate for transmission and distribution assets is based on historical outage and defect data. The outage data utilised was limited to planned and unplanned outages for maintenance works. The defect rate for zone substation assets is based on historical defect reports in the Asset Management System. Defect reports were considered more appropriate for zone substation as processes for reporting defects have historically been more robust than for transmission and distribution assets.
4. The forecast expenditure based on defect growth rates was then corrected by applying calculated step changes due to asset replacements and upgrade programs, as well as an allowance for ongoing improvements to Asset Management practices and operational efficiencies.
5. A reasonable estimate of travel expenses incurred by maintainers travelling to remote locations to perform corrective work was included.
6. An estimate for non-trades labour costs related to the planning, supervision and administration of the maintenance programs (i.e. planners, admin and other support staff) was also included.

10.5.3 Specific Maintenance

Specific maintenance activities address systemic or common issues across an asset class. Generally the tasks are one-off and therefore are not addressed through preventative maintenance tasks. Opportunities to address the issues in a cost effective manner are maximised by grouping tasks based on the skills and expertise required. The expenditure for this category was calculated for each task identified over the forecast period. Specific maintenance tasks were identified based on asset condition data, recent network inspections and analysis of reliability data.

10.5.4 Step changes incorporated into the maintenance expenditure forecasts

Step changes in the expenditure forecast occur when a significant change in the asset base occurs, changes to the preventative maintenance strategy are

implemented or network upgrades to improve operational efficiencies occur. Examples include:

- The replacement of existing zone substations;
- Construction of new zone substations, and transmission and distribution lines;
- An increase in rate of failure of a particular asset class due to ageing or changed service conditions;
- The identification of new maintenance activities required to improve asset reliability, or to address a known failure mode, safety or environmental risk; and
- Feeder upgrade programs which improve automation and fault location, reducing the time spent inspecting and locating faults on overhead lines.

Terminal and Zone Substations

The establishment of new zone substations and the replacement and upgrade of existing zone substations will result in a number of small step changes to the preventative maintenance expenditure forecast.

The establishment of new zone substations or capacity upgrades to existing zone substations results in a step increase in maintenance due to the significant increase in the asset base. Several new zone substations have recently been or will be established, such as Marrakai, Woolner, Leanyer and East Arm (interim solution) Zone Substations. In addition, several existing zone substations are to have their capacity upgraded, such as Frances Bay (second transformer and 66kV switchgear) and Palmerston (third transformer) Zone Substations.

Zone substation replacements have the opposite effect on maintenance expenditure. The oil-filled switchgear in existing zone substations is generally approaching end-of-life and is consequently maintenance-intensive, whereas new switchgear is either vacuum or SF6 insulated and requires less maintenance. In addition, assets generally require less comprehensive maintenance during their early life, further reducing maintenance costs. Several zone substation replacements are scheduled to occur, such as City Zone, McMinns and Berrimah Zone Substations.

Transmission and Distribution

There are step changes in distribution network expenditure during the period associated with the introduction of new maintenance activities, replacement of particular asset classes such as Oil Ring Main Units and the implementation of feeder upgrades, which are principally aimed at reducing the frequency and duration of network faults.

SCADA and Controls

No step changes are foreseen for the SCADA and Controls asset classification; however the number of assets is expected to increase at a higher rate than historically seen as Power Networks increases the level of automation throughout the

distribution network. This increase in automation and the introduction of an Integrated Distribution Management System will improve the reliability and efficiency of network operation; however these gains will be contingent on the reliability of SCADA and controls equipment in the field to provide the necessary information to the SCADA system.

10.5.5 Forecast maintenance expenditure

The forecast maintenance expenditure for the 2014-19 regulatory control period arising from the programs of work described in this section 10.5 is shown in Table 26.

Table 26 – Maintenance expenditure (\$ million, real \$2013/14 and escalated)

Year	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Maintenance expenditure	\$40.60	\$39.41	\$42.55	\$40.15	\$40.19	\$202.90

10.6 Operating and maintenance expenditure in the 2014-19 regulatory control period

The forecast operating and maintenance expenditure for the 2014-19 regulatory control period is shown in Table 27.

Table 27 – Operating and maintenance expenditure (\$ million, real \$2013/14 and escalated)

Year	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Operating expenditure	\$68.71	\$67.75	\$66.03	\$67.22	\$66.68	\$336.39
Maintenance expenditure	\$40.60	\$39.41	\$42.55	\$40.15	\$40.19	\$202.90
Operating and maintenance expenditure	\$109.30	\$107.17	\$108.58	\$107.37	\$106.87	\$539.29

This operating and maintenance expenditure has been used in the NTRM to determine Power Networks' revenue requirement and prices described in chapter 15.

10.7 Interaction between the capital, and operating and maintenance expenditure forecasts

The maintenance forecast expenditure model includes step changes related to planned capital expenditure during the period. An overview of these changes is included in section 10.5.4.

Asset replacements have a tangible impact by reducing expenditure associated with both preventative and corrective maintenance. These impacts have been considered in the maintenance expenditure forecasts.

The construction of new assets can also require an associated increase in expenditure to ensure the asset condition is maintained to an acceptable level. This has also been considered in the maintenance expenditure forecasts.

10.8 Contractual arrangements with external parties

There are a number of contractual arrangements in place within Power Networks. These arrangements include panel and period contracts. The use of these arrangements ensure operating and maintenance activities are performed efficiently and minimise operational risks associated with performing specialised tasks, maintenance of specialised equipment and ensuring competitive prices for materials and services. Some of the key contracts are described further below.

10.8.1 Vegetation Management

Vegetation management around overhead distribution and transmission lines is critical to network reliability and safety. Specialised service contractors are engaged on period contract arrangements to ensure that appropriately skilled personnel and specialised equipment is permanently located in the Northern Territory. Due to the small size and remote location of the network, maintaining a suitable level of service and availability necessitates the arrangement of period contracts to ensure a continuity of work for the relevant service provider.

10.8.2 Parts supply contracts

Supply contracts have been established with various vendors across the Northern Territory and interstate. The contracts will ensure that materials are supplied at a competitive price and within appropriate time frames.

10.8.3 Transformer condition monitoring services

This externally provided service is a whole-of-life asset management database for transformer maintainers and owners. The subscription database provides expert opinion and benchmarking of condition monitoring tests including dissolved gas analysis, winding resistance, frequency response analysis, degree of polymerisation and remanent life. The database provides a transformer health index, which takes into consideration benchmarked condition monitoring test results, along with discrete maintenance data for individual assets.

10.8.4 Insulating oil analysis

The analysis of insulating oil is performed using highly specialised laboratory equipment, which requires calibration and stringent quality control procedures.

Oil analysis is a core requirement for understanding the condition of several classes of network assets (principally transformers but also circuit breakers and instrument transformers).

External parties perform specialist oil analysis services for Power Networks. They use certified laboratories that are accredited to industry and international standards.

10.9 Efficiency and prudence of the operating & maintenance expenditure forecast

Each specific operating and maintenance expenditure category and major program has been justified against the Operational Expenditure Objectives and Criteria in each of the respective forecast operating and maintenance expenditure justification documents included at Confidential Attachment 24.

10.9.1 Efficient Costs

The efficiency of Power Networks' operational expenditure forecast is demonstrated by its efficient operating structure, efficient cost control and procurement policies and processes, and efficiency of its base year as demonstrated by benchmarking against industry peers.

Managing efficiency

The following sections outline Power Networks' overarching management strategies and systems for ensuring the efficiency of operating and maintenance expenditure forecasts.

Structure

Power and Water's owners and management have established an organisational structure that helps deliver efficient costs through the sharing of common indirect overheads among multiple utility service streams, including the standard control services.

Regulated network businesses in Australia have certain fixed operating costs due to the range of standard control services that must be provided to each customer, regardless of the number of customers.

Power Networks has the lowest number of standard control service customers in Australia, scattered across a territory that is the second largest in Australia. This diseconomy of scale is partially compensated for by economies of scope through Power and Water's multi-utility organisational structure.

The multi-utility model is a common international approach to achieving economies of scale and scope, particularly among local or municipal utility service providers.

In Power and Water's circumstances, adoption of a multi-utility structure enables the sharing of common corporate overheads associated with executive management, IT, legal, procurement, etc. among the electricity, water and sewerage operating businesses. These common corporate functions are largely a fixed cost that is shared between business units.

Despite the adoption of a multi-utility model, benchmarking against other utilities shows that Power Network's corporate overheads represent a larger share of total

expenditure relative to other electricity distribution networks.⁴⁵ This is due to their having two to twenty times more customers, which results in fixed costs of 50 per cent to 95 per cent lower by comparison.⁴⁶

The fixed costs impacted by these significant economies of scope are mainly found in Power Networks' corporate overheads listed above.

Operations

Internal labour represented approximately 40 per cent of Power Networks' total operating and maintenance expenditure in the base year, but is the key resource employed for internally provided services, which accounted for approximately 50 per cent of total operating and maintenance expenditure that same year.

Incurring new personnel costs is subject to a governance process that specifically requires testing of its efficiency as part of the approval process. As personnel provide standard control services using materials and other costs, this governance process provides an efficiency test of all proposed new operating costs.

Changes to personnel related expenditure must demonstrate the necessity of the expenditure and the efficiency of the recommended approach. The key efficiency tests embedded in the request for approval include:

- **Do Nothing** – What the costs and risks involved in not incurring the expenditure would be, and why they are not worth taking; and
- **Make/Buy** – Whether the function might be more cost effectively delivered by the market, and if not, why not.

The least cost option of trading off opex for capex is undertaken as part of the capital investment governance process, e.g. when making a systems investment to automate a manual process.

In addition to considering the efficiency of the proposed expenditure, the decision to incur it would be subject to any capital rationing processes. This could lead to under-investment relative to efficient levels where there is insufficient capital or operating budget to implement the optimal approach.

Over time and with adequate funding, this operating cost governance process could be expected to ensure the development of a least cost, efficient network operations forecasting function.

Maintenance

Power Networks manages the efficiency of its maintenance expenditure through a continuous improvement process oversight by an asset management governance

⁴⁵ Huegin Consulting, 2012 Distribution Benchmarking Study, p.31

⁴⁶ For example, a fixed cost of X per customer for one customer will be a fixed cost of X/2 for two customers.

process enshrined in its Maintenance Policy⁴⁷ and approvals process, and therefore reflected in the subsidiary asset strategy document⁴⁸.

Following on from the Casuarina Zone Substation incident in 2008 and the subsequent findings and recommendations of the Mervyn Davies Review, Power Networks established an enhanced asset management capability approach to address the shortcomings of the previous approach. This has resulted in the development of a comprehensive, industry benchmarked Asset Strategies Procedure, that is subject to review to ensure the strategies remain least cost and effective.

The ongoing identification and deployment of least cost asset maintenance strategies for each asset type means that the proposed maintenance tasks comprising the proposed maintenance expenditure are efficient with respect to the alternatives of do nothing and asset replacement (opex/capex trade-off).

Furthermore, the overall efficiency of the asset management function has been further supported by the investment in the Asset Management Capability project, which has established Maximo as Power Networks' Asset Management System. This represents an example of trading of capex for opex at the management systems level.

Power Networks' asset managers consider whether or not the market can provide maintenance services at a lower overall cost than Power Networks internal resources. Like most utilities, Power Networks has an internal trades/technical workforce that performs most of its maintenance services. Specialist services or services that can be provided at a lower cost are outsourced. Examples of market provided maintenance services include:

- Asset inspection;
- Vegetation management;
- Traffic management;
- Earth testing;
- On-load tap changer servicing; and
- Gas insulated switchgear servicing.

The Asset Management governance process ensures the proposed maintenance strategies and resulting expenditure are efficiently and effectively implemented. Importantly, the efficiency of optimal levels of maintenance expenditure is safeguarded at Power Networks through the principle of "Objective Need".

⁴⁷ Power Networks Maintenance Policy, 2013 (provided at Attachment 11).

⁴⁸ Power Networks Asset Strategies Procedure, 2013 (provided at Confidential Attachment 29).

Procurement

Ensuring the efficiency of Power Networks' operating and maintenance expenditure forecast requires that its input costs are as low as possible. This is achieved through the efficient forecast allocation of resources across internal and external providers depending on their relative costs, and the securing of the lowest possible sustainable prices from external service providers and suppliers through arrangements like period orders for some types of equipment.

Power Networks is governed within the Northern Territory Government's Procurement Framework. The principles are as follows:

- Best value for money;
- Open and affective competition;
- Enhancing the capabilities of local business and industry;
- Environment protection; and
- Ethical behaviour and fair dealing.

This ensures input prices are as low as possible and reflect current market rates. The relatively small local supply market in Darwin and high cost for new entrants to establish a presence means that input prices are higher than is the case in the larger Eastern states.

10.9.2 Prudent Costs

The following sections outline how Power Networks forecasting and budgeting approach has delivered operational expenditure forecasts that would be incurred by a prudent operator in Power Networks' circumstances.

Forecast development

Power Networks' proposed operational expenditure reflect the costs of a prudent operator because they are based on industry standard forecasting approaches developed by suitably qualified personnel, and which incorporate reasonable input assumptions.

Analysis of historical costs, cost drivers and anticipated future developments is undertaken within each operational expenditure category to develop reasonable estimates of future demand. These estimates may be based on a projection of historical relationships, industry standard forecasting methodologies, or stated policy, regulatory or business plans.

Table 28 presents the forecasting approach applied to each of the major operational expenditure forecasts. The specifics of each forecasting approach are described in detail in each of the individual category and project justifications. However, the two main approaches are projection of current trends and technical asset management models.

Table 28 – Expenditure Forecasting Approaches

Expenditure Category		Forecasting Approach
Operating Expenditure	Network Management	Projection
	Service Delivery	Projection
	Strategy and Planning	Projection
	Metering	Consultant recommendation and projection
	Regulatory Costs	Planned developments
	GSL Costs	Consultant recommendation and projection
	System Operations	Projection
	Corporate and Shared Services	Projection
	Other Costs	Consultant recommendation and projection
Maintenance Expenditure	Preventative Maintenance	Technical model
	Planned Corrective Maintenance	Technical model
	Unplanned Corrective Maintenance	Technical model
	Specific Maintenance	Technical model

Prior to forming the basis for planning and budgeting, these forecasts are reviewed by the relevant line manager to ensure that the inputs and outputs are reasonable.

This is particularly important for technical asset management models, which drive estimates of asset condition based faults, repair and maintenance expenditure. Projection based forecasts are also reviewed to ensure they reflect any scale economies.

Budget development

Power Networks' proposed operational expenditure reflects the costs of a prudent operator because they are based on long-term plans developed by suitably qualified personnel. Consistent with prudent behaviour, this approach achieves an appropriate balancing of near-term and long-term costs to achieve the lowest possible cost in present value terms.

Once the profile of future demand has been established through Power Networks' planning process, our line managers develop optimised budgets for meeting or managing demand, fulfilling planned future obligations, and addressing any associated safety, quality, reliability or security issues expected to arise.

Plans and their associated budgets are optimised over the planning horizon given identified risks and trade-offs between operating and capital investment costs. This process is particularly important for maintenance expenditure, where there can be significant safety risks associated with sub-optimal investment and expenditure patterns.

Operating expenditure budgets are also tested to ensure that they reflect a prudent level by considering the longer-term impact of reducing expenditure in the short term. For example, reducing the number of customer connection roles would reduce the quality of the connection process below the targeted service level.

Table 29 – Testing the Prudence of Operational Expenditure

Key	Expenditure category	Top three risks arising from material expenditure reductions
Operations	Network Asset Management	Understanding of condition degraded over time due to insufficient analysis
		Asset condition sub-optimal due to strategies becoming out of date; reduced opex efficiency
		Maintenance focus moves back to reactive, significant risk of catastrophic asset failure
	Network Planning	Understanding of demand patterns degraded over time due to insufficient analysis
		Network capacity sub-optimal due to insufficient planning, reducing capital efficiency
		Delays in connecting major new loads; load shedding in fast growing areas
	Network Engineering	Delays in processing new customer connections, breaching service targets
		Delays in developing network solutions for new and replacement projects
		Delays in connecting new loads; load shedding in fast growing areas
	System Operations	Delayed rectification of unplanned outages; fall in network reliability
		Fewer planned outages; unable to complete maintenance or add new capacity
		Unable to manage major network incident; return from black start significantly delayed
	Service Delivery	Insufficient resources for planned maintenance; sub-optimal asset maintenance
		Insufficient resources for planned capital works; delays in new and replacement projects
		Insufficient resources for field operations; limited access to network and lower reliability
	Metering	Delays in connection of new small customers; breach of service standards
		Unable to undertake replacement program; breach of technical code
		Unable to process all data and bill retailers; breach of Rules
	Regulation	Unable to establish compliance system; greater risk of non-compliance

Key	Expenditure category	Top three risks arising from material expenditure reductions
		Unable to provide regulatory reporting; breach of license conditions
		Unable to manage changes in regulatory framework; greater risk of non-compliance
Maintenance	Preventative	Loss of asset condition information; degraded asset management capability
		Missed opportunities to avoid in-service failure; increased unplanned maintenance
		Missed opportunities to avoid corrective maintenance; increased corrective maintenance
	Corrective - Planned	Missed opportunities to avoid in-service failure; increased unplanned maintenance
		Unsustainable growth in backlog drives move back to run to failure approach
		Significantly increased risk of catastrophic failure over time

Table 29 highlights a number of areas where the proposed level of expenditure has been tested against the expected impact on future risks and costs. In each case, it can be shown that a prudent operator would incur the proposed expenditure to avoid taking on an unreasonable level of risk, or to avoid being exposed to significantly higher future costs.

10.9.3 Realistic expectation

The following sections outline how Power Networks' operational expenditure reflects realistic expectations regarding key demand forecasts and cost inputs.

Forecast quantities

Power Networks' forecasts are based on a review of asset numbers and condition, planned investment activity, customer growth, and a detailed, bottom up estimate of maintenance tasks and effort. Forecast demand for operating and maintenance services are reviewed by line managers to ensure they are sensible and reasonable.

Network operations, repair and maintenance

Demand for network access, fault management, repair and maintenance services are mainly driven by the number and condition of network assets. The number of assets there are to maintain, and the condition of these assets, drive forecast demand for resources.

The forecast demand for these services is realistic because it is based on verified asset counts and condition data, defined and validated asset management strategies, and planned connections of new assets.

Customer service, metering and billing

Demand for customer operations including customer service, metering and billing are driven by customer numbers. The number of customers there are to connect and service, the greater the demand for these services.

The forecast demand for these services is realistic because it is based on forecasts of population growth, household formation, property development and economic growth as per Power Networks' Network Demand and Customer Connections Forecasting Procedure. These input forecasts have been sourced from recognised authorities such as the ABS.

Regulatory compliance

Demand for regulatory compliance is driven by planned policy and regulatory developments over the forecast period. While it is not possible to anticipate all policy and regulatory developments, it is reasonable to base demand on publicly announced plans.

The key regulatory and compliance demand driver is the transition to National Electricity Rules based regulatory framework over the forthcoming regulatory control period.

Forecast prices

Power Networks' unit price forecasts are based on market provided budget pricing where available, and independent expert advice on key input cost drivers where Power Networks delivers the services.

Labour, materials and services

Input prices for labour are based on current collective bargaining agreements, and market pricing for the range of externally provided services including IT license fees.

Forecasts of future prices for internal labour, materials and external services have been sourced from independent experts SKM and Deloitte. These estimates have been reviewed by Power Networks to ensure they are realistic.

Cost inputs included in proposed operational expenditure are therefore believed to be based on realistic expectations, as assessed by suitably quality practitioners in the field.

11 Service standards framework

The Commission has established a service standards framework, with which Power Networks must comply. There are two limbs to this framework:

- Guaranteed Service Level (GSL) arrangements, which provide financial compensation for customers if levels of service are less than targets set by the Commission; and
- Reliability targets and reporting arrangements. At this stage, there is no financial incentive associated with these targets although the Commission has indicated it may develop incentives similar to the AER's STPIS in future^{49,50}.

Code and Rule requirements

Clause 68(b) of the Code requires the regulator, in establishing a price or revenue cap, to have regard to the service standards agreed with customers or imposed on the network by the regulator.

Clause 6.6.2 of the Rules sets out the principles and requires the AER to establish a Service Target Performance Incentive Scheme (STPIS) for distributors, following consultation. This scheme is designed to provide incentives for distributors to maintain and improve a range of customer and reliability service standards.

This section describes how Power Networks has complied with the service standards framework during the current regulatory control period and describes how it will comply with the standards established for the 2014-19 regulatory control period.

11.1 Framework and Approach Decision

In its Framework and Approach Decision Paper, the Commission highlighted the importance of establishing service standards as part of the 'regulatory bargain' that balances of the interests of the regulated business and its customers.

The Commission has undertaken a review of the electricity standards of service framework in the Northern Territory. This review culminated in the release of a draft Electricity Standards of Service Code (ESS Code)⁵¹. Following a period of consultation, the final version of the new ESS Code took effect from 1 December

⁴⁹ AER, Electricity distribution network service providers Service target performance incentive scheme, November 2009. This scheme comprises four components:

- a 'reliability of supply' component;
- a 'quality of supply' component;
- a 'customer service' component; and
- a guaranteed service level (GSL) component.

⁵⁰ Utilities Commission, 2014-2019 Network Price Determination Framework and Approach Decision Paper, November 2012, p. 76.

⁵¹ Utilities Commission, Northern Territory of Australia Electricity Standards of Service Code, 1 December 2012.

2012. The Guaranteed Service Level Code (GSL Code) took effect on 1 January 2012, with full implementation on 1 July 2012⁵².

The Commission has also indicated its intention to consider Power Networks' service standards when assessing the revenue proposal.

11.2 Service standard framework

There are two elements to the service standards framework to which Power Networks is subjected. These are the GSL Code, and the network reliability standards set out in the ESS Code.

11.2.1 Guaranteed Service Levels

The GSL Code took effect from 1 January 2012, with a staged approach to the implementation of payments for various service performance measures. The GSL Code was fully implemented on 1 July 2012.

11.2.2 Network reliability standards

The final version of the ESS Code contained significantly different reporting standards to the standard NEM arrangements for which Power Networks had been gathering information and assessing its performance, principally in the area of exclusions and the treatment of planned interruptions. At this time, there has been insufficient opportunity to recreate the historical performance of the network and understand the implications of the new standard on capital and operating expenditure forecasts.

Power Networks has therefore assessed its historical performance and the expenditure forecasts in this Proposal on the basis of the former standards. It is envisaged that a variation to the expenditure forecasts to recognise the revised reporting standards and targets will be submitted with Power Networks' Revised Regulatory Proposal.

11.3 Power Networks' service performance

This section sets out Power Networks' historic service performance and its proposal for network performance during the 2014-19 regulatory control period.

⁵² Utilities Commission, Northern Territory of Australia Guaranteed Service Level Code, 1 January 2012

11.3.1 Service performance during the 2009-14 regulatory control period

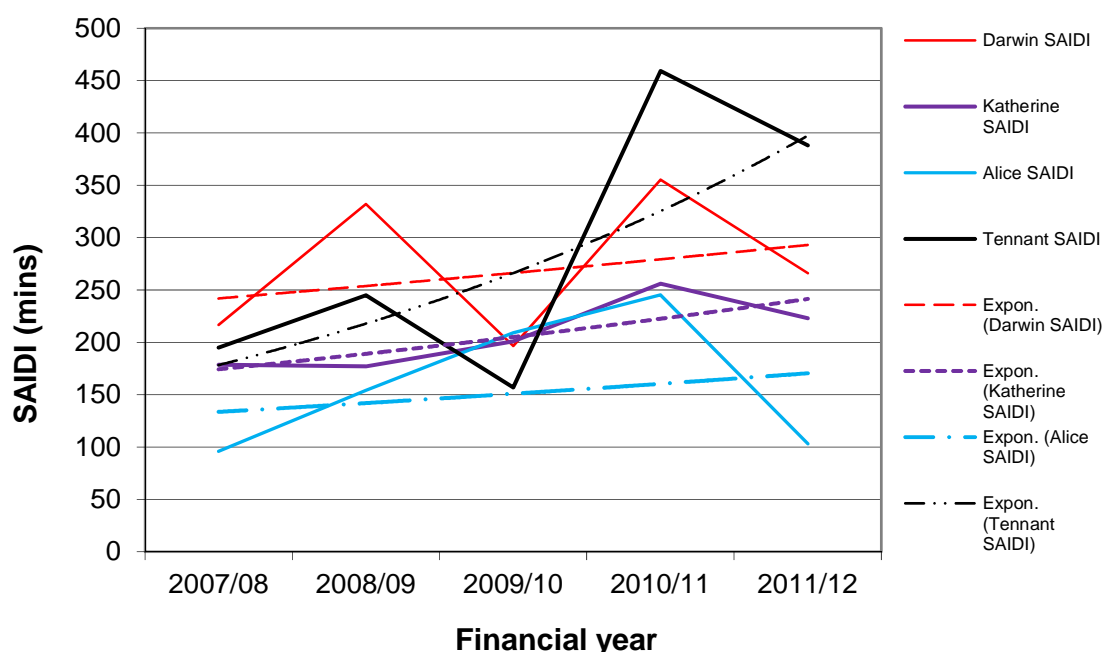
The ESS Code sets out the acceptable levels of system reliability for the Northern Territory. Consistent with the target setting methodology in the ESS Code, target standards have been calculated by averaging data from the preceding five financial years. The subsequent target standards are presented by region in Table 30.

Table 30 – Calculated five year average SAIDI target standards

Region	Five year SAIDI target standard (mins) ⁵³
Darwin	258
Katherine	182
Alice Springs	153
Tennant Creek	265

Power and Water's actual distribution network performance by region is shown in Figure 17. Trends applied to the data represent declining levels of service performance over the five-year period 2007/08 to 2011/12.

Figure 17 - System SAIDI five year performance and trends



⁵³ Power and Water use the SCNRFR Feeder Categories and IEEE 1366 2.5 beta method for Major Event Day exclusions.

11.3.2 Service performance during the 2014-19 regulatory control period

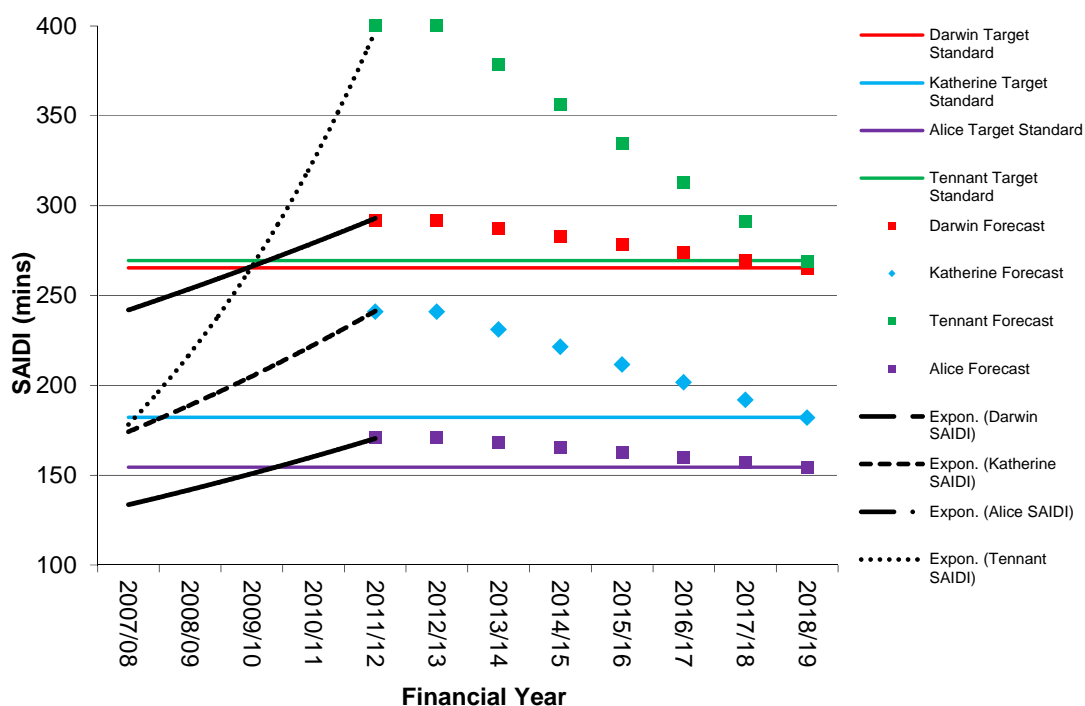
To meet the Target Standards as set out by the ESS Code an improvement in SAIDI is required in all regions. The 2011/12 SAIDI trend value, the calculated System SAIDI Target Standard and the required SAIDI Improvement is shown in Table 31

Table 31 – 2011/12 System SAIDI trend, target standard and improvement

Region	2011/12 trend value (mins)	System SAIDI target standard (mins)	Required SAIDI improvement (mins)
Darwin	292	258	34
Katherine	241	182	59
Alice	171	153	18
Tennant Creek	400	265	135

The Power Networks' annual Feeder Upgrade Program is proposed to improve reliability within the distribution network to achieve the target standards by the end of the 2014-19 regulatory control period. Reliability trends for all regions over the previous five years and the forecast reliability performance during this period is shown in Figure 18.

Figure 18 - System SAIDI five year trends and forecasts



Feeder Upgrade Program

Power Networks' Feeder Upgrade Program targets poorly performing areas on the distribution network. Each year Power Networks develops feeder performance reports for all poorly performing feeders. These reports include analysis of five years of historical outage data and interruption causes. The results of the analysis drive targeted feeder upgrades planned for the upcoming financial year.

Feeder performance is continually monitored to determine the success of the feeder upgrades and improvement works. The timing of the feeder analysis process has also been revised to calendar years to allow for works planning in the following financial year. This change allows for a more timely response to developing issues.

Following the analysis on poorly performing feeders, upgrades are scheduled and project requests handed over to the relevant work groups for delivery. Task completion is reported monthly.

Specific feeder upgrade options

The following outlines the typical works requested on the poorly performing feeders as a part of the feeder upgrade program.

Hardware upgrades

Hardware upgrades include the replacement of insulators, the installation of fibreglass cross arms, conductor spacers and the installation of bat guards. These measures are expected to improve lightning performance and minimise interruptions due to animal interference on poorly performing feeders.

Network reconfigurations including recloser installation

On poorly performing feeders prone to transient faults caused by vegetation, weather and/or animals, auto-reclosing at key network locations reduces the outage impact and improves restoration times, through greater sectionalisation and remote operation. Gas circuit reclosers are being installed on selected, poorly performing feeders to achieve this outcome.

Air break switch to gas break switch changeovers

Air break switches are changed over to remotely controlled gas break switches in strategic locations, to improve interruption restoration times. Poorly performing feeders with high interruption durations have been targeted for this program.

Cable testing and replacement

High voltage cables are tested and condition assessed to determine if replacement is required. Cables with more than two or three failures are scheduled for replacement. Poorly performing feeders with a high incidence of cable failures have been targeted for priority testing and replacement programs.

12 Regulatory asset base

Network businesses are asset intensive and the regulatory asset base (RAB) is the most important component of the building block revenue, in that it affects both the return on and return of assets. The return on capital is the asset value multiplied by the WACC, while the return of capital is the depreciation component of revenue. Taken together, these components typically represent the majority of the network revenue.

There are a number of approaches to determining the opening asset value for the 2014-19 regulatory control period, the two principal alternatives being:

- The opening asset base for the 2014 regulatory control period may be established from roll-forward of the asset base in 2009, taking account of capital expenditure, depreciation and asset disposal over the previous regulatory period; or
- The asset base may be revalued at the commencement of the new regulatory control period.

In order to provide a return on efficient capital investment undertaken by the network provider to maintain or extend network capacity that is commensurate with the commercial and regulatory risks involved, and based on generally accepted regulatory practice under the Rules framework, Power Networks proposes that revaluation of its network assets is appropriate.

This chapter sets out the reasons why Power Networks proposes the revaluation of its RAB, the process that has been followed and the resulting opening RAB for 1 July 2014.

Code and Rule requirements

Schedule 6, clause 4 of the Code deals with the regulatory asset base (RAB) used in the first regulatory control period for determining the network provider's revenue cap.

Clauses 4(2) to 4(6) describe how the RAB must be determined based on efficient technology and optimisation to remove redundant or oversized assets. The optimised and depreciated value of the network (ie. ODRC) is to be used to determine the return of capital.

Schedule 7, clause 6 of the Code covers the addition of assets to the RAB and any revaluation of the RAB in the second and subsequent regulatory control periods. In approving the basis of asset valuation, the regulator must have regard to –

- (a) the agreement of the Council of Australian Governments of 19 August 1994 that deprival value should be the preferred approach to valuing network assets;
- (b) any subsequent decisions of the Council of Australian Governments regarding the valuation of public sector assets; and
- (c) generally accepted regulatory practice at the time.

The principle to be followed by the regulator in making a determination on asset values is set out in clause 68(e):

"the provision of a return on efficient capital investment undertaken by the network provider in order to maintain or extend network capacity that is commensurate with the commercial and regulatory risks involved;"

Schedule 6.2 of the Rules deals with the establishment of the opening RAB for a distribution system, whether or not the RAB was previously subject to a building block determination. The RAB is rolled forward in accordance with the provisions of clause 6.5.1, using the roll forward model established by the AER.

The opening values of individual DNSPs upon becoming subject to the Rules framework are set out in clause S6.2(c)(1).

12.1 Background to the establishment of the 2009 RAB

The Commission's 2004 Networks Price Determination was made on the basis of an Optimised Depreciated Replacement Cost (ODRC) valuation for the RAB. However, the Commission made provision in this determination for an adjustment to the revenue cap in the event of a material error in the asset values that had been used.

In 2005 the Commission made an "Off-Ramp" decision to reduce Power Networks' RAB, on the basis that the original asset valuation of \$430.5 million as at 1 July 2002 had not been estimated accurately. The Commission reduced Power Networks' RAB value to \$350 million, as at 1 July 2002^{54,55}. In so doing, it interpreted the regulatory objectives in clause 63 and the asset valuation basis in Schedule 7.6(2) of the Code as permitting it to determine a plausible range of asset valuation between:

- "a) at the lower bound, the book value of those assets; and*
- b) at the upper bound, the true ODRC value of those assets⁵⁶"*

This "line in the sand" decision on the RAB resulted in a reduction in network tariffs by an average of 11.5 per cent.

In the 2009 Networks Price Determination, the Commission reaffirmed its 2005 Off-Ramp decision and rolled forward the RAB with allowance for capital expenditure, depreciation, indexation and disposals. The resultant RAB value as at 1 July 2009 was \$460.5 million⁵⁷.

12.2 Framework and Approach Decision

The Commission has indicated that it does not intend to reconsider re-opening the initial regulatory asset base, determined at \$350 million as at 1 July 2002⁵⁸.

That asset base would be rolled forward from 30 June 2009 to 1 July 2014 with adjustment for inflation, depreciation, capital expenditure actually incurred and asset disposals using the AER's Roll Forward Model.

⁵⁴ Utilities Commission, Networks Pricing: Asset Valuation Off-Ramp Final Decision - Statement of Reasons, April 2005.

⁵⁵ Utilities Commission, 2004 Regulatory Reset Asset Valuation Off-Ramp Final Decision, April 2005.

⁵⁶ Utilities Commission, Networks Pricing: Asset Valuation Off-Ramp Final Decision - Statement of Reasons, April 2005. clause 4).

⁵⁷ Utilities Commission, Final Determination - Networks Pricing: 2009 Regulatory Reset, March 2009, p. 56.

⁵⁸ Utilities Commission, 2014-2019 Network Price Determination Framework and Approach Decision Paper, November 2012, p. 59.

12.3 Deprival value

Schedule 7, clause 6 of the Code makes reference to the COAG preference for the deprival value for network assets.

The deprival value of assets is usually defined as the lesser of:

- the ODRC; and
- the economic value of the asset which is calculated as the maximum of:
 - the net present value of the future cash flows; and
 - the net realisable value from selling the assets for their scrap value.

In practice, the economic valuation limb has infrequently been used in Australia because its use in the regulatory context involves a degree of circularity. Regulated revenues determine future cash flows and hence the value of the assets. An asset valuation below ODRC represents a “line in the sand” imposed by the regulator to lock in tariffs at lower levels than could be delivered by an optimal network.

12.4 Approach in the National Electricity Market

Upon transition to the NEM regulatory framework, the network businesses in the NEM jurisdictions were established with an opening RAB value nominated by their respective jurisdiction. These asset values are contained in clauses S6.2.1 of the Rules for Distribution Network Service Providers. Since entry to the NEM, the RAB values of these businesses have been rolled forward in accordance with Rules clauses 6.5.1. In its statement of regulatory principles, the ACCC stated at the time:

"The main economic principle for assessing the economic value of any asset is that its value to investors is equal to the present value of the expected future cash flows generated by those assets. The practical difficulty in making this assessment for regulated monopoly businesses is that the future revenue derived from the assets is determined by the regulator.

This circularity can be eliminated by the use of the ODRC approach. The ODRC methodology divorces the asset valuation from the assumed profile of revenues that an asset may generate⁵⁹.

The method that was adopted by jurisdictional regulators across Australia for the initial valuation of assets under the building block model was the depreciated optimised replacement cost (ODRC) methodology. This approach avoids the circularity associated with the regulator estimating an asset value that is supported by a revenue stream that is determined by the regulator.

⁵⁹ ACCC, Statement of principles for the regulation of electricity transmission revenues - background paper, 8 December 2004.

A summary of the asset valuation approaches by Australian jurisdictions is shown in Table 32.

Table 32 – Methodologies used in the context of electricity networks⁶⁰

Regulator	Network	Value Determined by	Method used to determine initial asset value	Role of prices in determination
Transmission				
ACCC/AER	TransGrid (NSW)	Regulator	ODRC	n.a.
	Powerlink (Qld)	Qld Gvt	ODRC	n.a.
	ElectraNet (SA)	SA Gvt	ODRC	n.a.
	SP AusNet (Vic)	Vic Gvt	ODRC	n.a.
	TransEnd (Tas)	Tas Gvt	ODRC	n.a.
Distribution – Jurisdictional Regulators				
ORG/ESC Victoria	Solaris Power, CitiPower, Powercor, Eastern Energy (EE) and United Energy (UE)	Vic Gvt	Solaris	Asset value > ODRC
			CitiPower	Asset value > ODRC
			UE	Asset value > ODRC
			EE	Asset value < ODRC
			Powercor	Asset value < ODRC
SAIPAR/ ESCOSA South Australia	ETSA Utilities	SA Gvt	ODRC	n.a.
IPRC/ICRC ACT	ActewAGL	Regulator	ODRC	n.a.
IPART New South Wales	EnergyAustralia, Integral and Country Energy	NSW Gvt	ODRC	n.a.
OTER Tasmania	Aurora	Regulator	ODRC	n.a.
QCA Queensland	Energex and Ergon	Regulator	ODRC	n.a.
ERA Western Australia	Western Power (Transmission and Distribution)	Regulator	Asset value < ODRC	n.a.

All of the NEM jurisdictions prescribed asset values that were based on ODRC, upon their entry to the NEM and the exposure of their businesses to the Rules framework. The adjustments between distributors in the case of Victoria were to initially preserve uniform state-wide pricing, following the disaggregation of the SECV.

⁶⁰ Reproduced from NERA and PricewaterhouseCoopers, Initial Value of Regulatory Assets - the Australian Experience, Report for Orion and Powerco, 6 December 2009, Table 3.1, p. 7.

12.5 Power Network's RAB as at 1 July 2014

The Commission has proposed to adopt, where practicable, the approach used by the AER and those parts of Chapter 6 of the Rules, to the extent that they are consistent with the Code.

The Rules establishes the RAB at the start of the regulatory control period. This is (or should be) a measure of the financial value invested in a network business by its owner, in order that the return on and of that investment should be consistent with the national electricity objective, as follows:

"7—National electricity objective

The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—

- (a) price, quality, safety, reliability and security of supply of electricity; and*
- (b) the reliability, safety and security of the national electricity system.⁶¹*

The majority of network assets have very long lives and Power Networks considers that the current regulatory "line in the sand" approach to valuing the RAB does not fully recognise the value of past investments and therefore does not conform with the national electricity objective in respect of promoting efficient investment in the long term interests of electricity consumers.

Clause 68 of the Code expresses a similar objective, to which the Regulator must take account of in setting the network revenue:

- (e) the provision of a return on efficient capital investment undertaken by the network provider in order to maintain or extend network capacity that is commensurate with the commercial and regulatory risks involved;

Power Networks does not accept that the "line in the sand" approach adopted by the Commission in its 2009 Networks Price Determination provides for an efficient return on capital for its investment in the network. The optimisation process followed in establishing the ODRC is considered to deliver a much more appropriate means of establishing the efficient value of that investment.

It should also be noted that Power and Water is required to change its accounting policy to recognise the 'fair value' of assets by 30 June 2014. To this end Power and Water has revalued the Power Networks assets on the basis of ODRC as an accepted method of determining fair value.

⁶¹ South Australia, National Electricity (South Australia) Act 1996, National Electricity Law section 7.

Power Networks proposes that the opening RAB for the 2014-19 regulatory control period should be based on the ODRC revaluation of assets. This Proposal aligns with the provisions of the Rules and also conforms with:

- Schedule 7.6(2)(a) of the Code, that deprival value should be the preferred approach to valuing assets; and
- Schedule 7.6(2)(c) of the Code, being generally accepted regulatory practice at the time.

To this end, Power Networks commissioned SKM to undertake the ODRC valuation of its network assets. This asset valuation is at 1 July 2013. Power Networks proposes to establish the RAB by rolling this value forward to 1 July 2014, rather than by rolling forward the 2009 RAB throughout the 2009-14 regulatory control period. However, both sets of roll forward and revenue models have been provided as Attachment 14 to Attachment 17.

12.6 Power Networks' 2013 ODRC valuation

The ODRC of the network is the sum of the depreciated optimised replacement cost of its respective assets. It measures the cost of replicating the service potential of the network in the most efficient way possible, from an engineering perspective. This approach:

- Is based upon the cost of modern equivalent assets, effectively taking account of technological developments;
- Removes from the asset base those assets that are no longer required or optimises those with a higher capacity than required within planning horizons; and
- Allows for the service life of the asset which has expired in the valuation.

The optimisation provided in the ODRC process is directed towards identifying the most efficient facilities necessary to produce a specified level of services.

Power and Water has revalued the network assets with the assistance of an experienced consultant, SKM. SKM's ODRC valuation of Power Networks' assets is included as confidential Attachment 32 to this Proposal.

12.6.1 SKM's approach to establishing the ODRC valuation

Power Networks engaged SKM to conduct its ODRC valuation as part of a broader organisational valuation process. This decision was based in part on SKM's familiarity with Power Networks' regulated transmission and distribution assets, as a result of conducting the asset verification and valuation assignment on the whole of Power and Water's business assets in 2007.

Power Networks understands that SKM has undertaken the majority of transmission and distribution asset valuations for Australian networks businesses over the past 10 years, including the revaluation of assets for the New South Wales and Queensland distribution businesses prior to their entry to the NEM.

SKM's ODRC approach consisted of four key steps:

- Construct a list of modern equivalent assets which are representative of the range of assets that exist on the network;
- Establish the current replacement cost of the modern equivalent assets in service at the valuation date;
- Depreciate the replacement costs to reflect the expended and hence, remaining life of the asset in service; and
- Adjust the depreciated replacement costs for over design, over-capacity and redundant assets (optimisation).

Optimised Depreciated Replacement Cost (ODRC) of assets is also the corner stone methodology for the determination of the Optimised Deprival Valuation (ODV) of utility assets for incorporation into a regulatory asset base (RAB). The ODRC methodology is widely used in other countries and regulatory jurisdictions, including the United Kingdom, the Philippines, New Zealand, Singapore and Canada.

As noted above, the Optimised Deprival Valuation (ODV) is defined as the lesser of Optimised Depreciated Replacement Cost (ODRC), and Economic Value (EV). The underlying philosophy of the ODV methodology is to "value the assets at the level at which they can be commercially sustained in the long term, and no more. The resulting value should be equal to the loss to the owner if they were deprived of the assets and they took action to minimise their loss."

12.6.2 Data Validation of the 2013 Valuation

As part of the 2013 ODRC valuation exercise SKM undertook field inspections of the assets at seven zone substations, six transmission lines and nine distribution areas.

The purpose of the audits was to:

- Confirm that the assets in the field were accurately recorded in the Maximo data set provided to SKM;
- Identify if there were assets in the Maximo data set provided to SKM that were absent in the field; and
- Provide a general assessment of the condition of the assets.

SKM considered that a minimalist approach was sufficient in the case of Power Networks because of the much larger asset validation exercise undertaken in 2007 by SKM. In particular, they noted about the 2007 validation that:

*"The extensiveness of the field visitation program was far greater than has been normally conducted for other utilities that SKM is familiar with."*⁶²

⁶² Proposal letter from SKM to Power Networks dated 13 February 2013

SKM has listed a number of data discrepancies that were uncovered during the valuation process. SKM note that "due to the minimalist nature of the audit, SKM cannot comment on the materiality of these discrepancies."⁶³

Based on its transition to a world class asset management system, Maximo, and the positive findings of the SKM review of its data integrity, Power Networks believes that the accuracy of its asset records is now equivalent to best practice levels, and therefore provides substantial confidence in the robustness of the valuation outputs.

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

⁶³ SKM 2013 Op Cit p. 23.

12.7 Comparing ODRC and RFM Valuations

The results of the SKM ODRC valuation by asset category, and its comparison to the UC preferred RAB as derived by the roll forward model as at 1 July 2013 are summarised by asset category in Table 33.

Table 33 – Opening asset base as at 1 July 2013 (\$ million, nominal)*

Equipment category	SKM Valuation			UC preferred RAB	Difference between RAB and ODRC
	Depreciated Replacement Cost	Optimised Amount	ODRC		
Transmission terminal station	\$39.1	\$0.3	\$38.8	\$64.0	-\$25.3
Zone substation	\$215.6	\$2.7	\$212.8	\$252.0	-\$39.2
Transmission lines	\$170.2	\$6.7	\$163.5	\$144.9	\$18.5
Distribution mains	\$297.9	-	\$297.9	\$303.8	-\$5.9
Distribution substations	\$85.9	\$4.7	\$81.3	\$20.3	\$61.0
Metering	\$7.7	-	\$7.7	\$4.0	\$3.7
Land and easements	\$33.0	-	\$33.0	\$11.6	\$21.4
Secondary systems – control communications and protection	\$9.6	-	\$9.6	\$13.4	-\$3.8
Other	-	-	-	\$1.0	-\$1.0
Non-network - IT and Communications	\$3.4	-	\$3.4	\$0.0	\$3.4
Non-network - Plant & Equipment	\$8.2	-	\$8.2	\$16.3	-\$8.1
Non-network - Other	-	-	-	\$1.5	-\$1.5
Total	\$870.6	\$14.4	\$856.2	\$832.89	\$23.3

*The numbers may not sum due to rounding.

The key outcomes to note from the ODRC valuation results include:

- The ODRC valuation is currently \$23.3 million above the roll forward model derived RAB. Power Networks believes this confirms our previous concerns that the 2005 asset valuation off-ramp decision undervalued Power Networks' asset base;
- That the SKM assessment of a \$14.4 million optimisation (or 1.7 per cent of Depreciated Replacement Cost) would indicate that Power Networks has been prudent and efficient in its network investment process to date; and
- Over the last four years considerable effort has been made to produce an accurate asset listing as part of the process of implementing the new Asset Management system, Maximo. The asset listing that now exists in Maximo is considered an accurate account of Power Networks' assets, having undergone field verification exercises and then further validated by SKM as part of the

asset valuation project. Power Networks' preventative maintenance plan is based on this asset listing and is embedded within the Maximo system. As shown in the table above, there is considerable difference in the valuation of individual asset classes. For example, there is a \$61 million difference between the ODRC and the RAB for the distribution substations asset class. Given this, Power Networks recommends that the SKM valuation form the basis of the 2014 RAB.

A comparison between the ODRC valuation shown above and the roll forward model from 1 July 2009 RAB to June 2014 is shown in Table 34.

Table 34 – RAB roll forward – Annual closing RAB (\$ million, nominal)

Year	2009/10	2010/11	2011/12	2012/13	2013/14
ODRC	-	-	-	856.18	930.06
UC preferred	585.07	669.40	734.32	832.89	916.35

12.7.1 ODRC as at 1 July 2014

For the reasons set out in sections 12.4 to 12.6, Power Networks therefore proposes an opening valuation for the RAB of \$930.06 million, as at 1 July 2014. This is based on replacing the 30 June 2013 roll forward model RAB with the SKM ODRC valuation. The AER's Roll Forward Model (RFM) was used to develop the opening asset base as at 1 July 2014. The completed model is included as Attachment 14.

The ODRC RAB value has been included in the NTRM for the purposes of calculation of the Power Networks' proposed revenue and network prices for the 2014-19 regulatory control period.

12.8 Roll forward of the RAB value from 1 July 2014 to 30 June 2019

The opening RAB of \$930.06 million has been rolled forward throughout the 2014-19 regulatory control period using the NTRM.

The outcome of rolling forward the RAB throughout the 2014-19 regulatory control period is shown in Table 35.

Table 35 – RAB roll forward – Annual closing RAB (\$ million, nominal)

Year	2014/15	2015/16	2016/17	2017/18	2018/19
RAB – ODRC	988.21	1,035.18	1,068.93	1,092.09	1,124.91

13 Weighted average cost of capital

The Weighted Average Cost of Capital (WACC) is used to determine Power Networks' return on assets throughout the 2014-19 regulatory control period. It is therefore an important component in determining the allowable revenue.

Both the Code and Rules establish the principle of a level playing field - that is, the return on assets for a network business should be the same as that of a commercial enterprise facing similar business risks. In addition, the Code permits the Commission to make a determination on the WACC that is consistent with generally accepted regulatory practice.

The Rules embodies a post-tax framework, in which the estimated cost of corporate income tax is permitted as an expense in determining the allowable revenue. This approach differs from the pre-tax framework that the Commission applied to the determination of Power Networks' prices in 2009.

13.1 Framework and Approach Decision

Power and Water has sought, and the Commission has agreed, to retaining the pre-tax framework for the 2014 Networks Price Determination⁶⁴. This will involve the use of a pre-tax WACC and has also required modifications to the AER's financial model use to calculate revenue (the PTRM).

This section sets out the arrangements to apply to the determination of WACC. An indicative pre-tax WACC based on this approach has been used to determine the revenue and prices in this Proposal.

Code and Rule requirements

Clause 68(d) of the Code establishes the principle that the network provider's cost of must be determined having regard to the risk-adjusted rate of return required by investors in commercial enterprises facing similar business risks to those faced by the network provider in the provision of that service.

Code Schedule 8 sets out the calculation approach for the first regulatory control period.

In subsequent regulatory control periods, the WACC methodology is required under Schedule 8 clause 1(2) and clause 63(aa) to provide an expected revenue for regulated services that is at least sufficient to meet the efficient long-run costs of providing that regulated service or services, and includes a return on investment commensurate with the commercial and regulatory risks involved, and be consistent with generally accepted regulatory practice at the time.

Rules clause 6.5.2(c) articulates the same principle as Code clause 68(d). The manner in which the associated parameters in the formula are established is in Rules clauses 6.5.2(d) to 6.5.2(l).

The requirement for, and content of, the AER's Rate of Return Guidelines are established in Rules clauses 6.5.2(m) to 6.5.2(q).

Because a post-tax framework is embodied in the Rules framework, clause 6.5.3 establishes the estimated cost of corporate income tax. This is treated as an operational expense in determining the DNSP's revenue.

⁶⁴ 2014-2019 Network Price Determination Framework and Approach Decision Paper, November 2012, p. 71.

13.2 Conversion from post tax to pre tax framework

Post tax formulation of WACC

The post tax formulation of the nominal vanilla WACC is set out in the savings and transitional provisions in chapter 11 of the Rules and is as follows:

$$WACC_{\text{Post tax}} = k_e \times \frac{E}{V} + k_d \times \frac{D}{V}$$

where:

k_e is the return on equity (determined using the Capital Asset Pricing Model) and is calculated as:

$$k_e = r_f + \beta_e \times MRP$$

where:

r_f is the nominal risk free rate for the *regulatory control period* determined in accordance with paragraph (c);

β_e (the equity beta) is deemed to be 1.0; and

MRP (the market risk premium) is deemed to be 6.0 per cent;

k_d is the return on debt and is calculated as:

$$r_f + DRP$$

where:

DRP is the debt risk premium for the *regulatory control period*;

E/V is the value of equity as a proportion of the value of equity and debt, which is $1 - D/V$; and

D/V (the value of debt as a proportion of the value of equity and debt) is deemed to be 0.6.

Taxation expense

The estimated cost of corporate income tax (ETC_t) is calculated in accordance with clause 6.5.3 of the Rules:

$$ETC_t = (ETI_t \times r_t) (1 - \gamma)$$

where:

ETI_t is an estimate of the taxable income for the regulatory year earned by a benchmark efficient entity providing standard control services, in accordance with the PTRM;

r_t is the expected statutory income tax rate for the regulatory year

γ (the assumed utilisation of imputation credits) is deemed to be 0.5.

This taxation expense is not included as a building block component in the pre tax framework.

Pre tax formulation of WACC

The AER's PTRM has been modified by the Commission to include pre tax formulation of WACC, as follows:

$$WACC_{pre\ tax} = k_e \times \frac{1}{1 - T_e \times (1 - \gamma)} \times \frac{E}{V} + k_d \times \frac{D}{V}$$

Where T_e is the effective tax rate for equity determined from the PTRM.

13.3 The Commission's Framework and Approach Decision Paper

In the Framework and Approach Decision paper, the Commission indicated its preferred approach to the determination of WACC parameters, based on the AER's draft determination for Aurora. These parameters are reproduced in Table 36.

Table 36 - Utilities Commission preferred approach - WACC parameters

Set parameters		Commission's preferred approach
Gearing	$\frac{D}{V}$	60 per cent
Nominal risk-free rate	r_f	10-year Commonwealth Government Security
Market risk premium	MRP	6.0 per cent
Equity beta	β_e	0.8
Credit rating		10 year BBB+ based on observed market data
Gamma	γ	0.25

In the final determination for Aurora, the AER confirmed these WACC parameters, with the exception of the credit rating classification, which is used to determine the Debt Risk Premium (DRP)⁶⁵. In relation to the DRP, the AER accepted a decision by the Australian Competition Tribunal⁶⁶, and adopted the Bloomberg BBB rated fair value curve (FVC) to estimate the DRP extrapolated to a 10 year term, consistent with Aurora's revised regulatory proposal.

⁶⁵ AER, Final Distribution Determination - Aurora Energy Pty Ltd, 2012/13 to 2016-17, April 2012, pp. 27, 31.

⁶⁶ Australian Competition Tribunal, Application by Envestra Ltd (No 2) [2012] ACompT 3, 11 January 2012, paragraph 120; Australian Competition Tribunal, Application by APT Allgas Energy Ltd [2012] ACompT 5, 11 January 2012, paragraph 117; and Australian Competition Tribunal, Application by United Energy Distribution Pty Ltd (No 2) [2012] ACompT 1, 6 January 2012, paragraph 462.

Notwithstanding that the AER was obliged to change its approach to calculating the DRP in the final Aurora determination, the Commission has indicated its preference to retain the AER's approach from the draft Aurora determination, on the basis that:

*"... it is reasonable to assume that the approach set out in the draft Tasmanian determination will be reflected in the new guidelines to be developed by the AER."*⁶⁷

13.4 AER Rate of Return Guidelines

The AER is currently undertaking a consultation process to establish the Rate of Return Guidelines, as required by Rules clauses 6.5.2(m) to 6.5.2(q). The AER's program for this consultation calls for publication of the final Guidelines by 29 November 2013.

In the May 2013 Consultation Paper, the AER has canvassed a number of ways in which the Return on Debt may be calculated for a regulated business⁶⁸. These approaches include:

- Continuation of the current "on the day" approach, using a typical market observation period of 20 business days immediately prior to the determination;
- The adoption of a averaged portfolio approach, with the benchmark portfolio of debt having staggered maturity dates; or
- A hybrid approach combining these techniques.

The AER has expressed the preliminary view:

*"... we are open to the application of a portfolio approach."*⁶⁹

In view of the many interrelated issues being considered by the AER in relation to determining the rate of return, and the preliminary view expressed by the AER, Power Networks does not consider that it is reasonable to assume that the approach to estimating the return on debt set out in the draft Tasmanian determination will be reflected in the new guidelines to be developed by the AER.

Moreover, the approach proposed by the Commission in its Framework and Approach Decision Paper is not consistent with *"generally accepted regulatory practice at the time"*, as is required by Schedule 8, clause 1(2) of the Code.

As a consequence, Power Networks proposes that the approach to estimating the DRP adopted by the AER in the final Aurora determination should be used for Power Networks.

⁶⁷ 2014-2019 Network Price Determination Framework and Approach Decision Paper, November 2012, p. 69.

⁶⁸ AER, Consultation paper - Rate of return guidelines, May 2013, pp. 46-57.

⁶⁹ Ibid, p. 55.

13.5 Power Networks' proposed WACC parameters

Power Networks accepts the Commission's proposed WACC parameters in Table 36, with the exception of the credit rating used to determine the DRP.

Power Networks proposes that the approach adopted by the AER for the final Aurora determination should be used by the Commission, with the Bloomberg BBB rated FVC used to estimate the DRP, extrapolated to a 10 year term. This is demonstrably "*generally accepted regulatory practice at the time*" as applied by the AER to Aurora and several other network businesses.

For the purpose of developing an indicative revenue trajectory and associated prices, Power Networks proposes the WACC parameters set out in Table 37. These are based on the AER's final Aurora determination. The final determination will substitute the DRP observed in a market observation period closer to the date of the Final Networks Price Determination.

Table 37 - Power Networks' proposed WACC parameters

Parameter	Power Networks Proposal
Nominal risk free rate	3.89%
Equity beta	0.80
Market risk premium	6.00%
Gearing level (debt/debt plus equity)	60%
Debt risk premium	4.11%
Assumed utilisation of imputation credits (gamma)	0.25
Inflation forecast (average)	2.60%
Cost of equity	8.69%
Cost of debt	8.00%
Nominal vanilla WACC	8.28%
Pre tax nominal WACC	8.80%

14 Depreciation

This chapter sets out Power Networks' proposed depreciation and amortisation arrangements, and demonstrates that the proposed arrangements are consistent with the requirements of the Code and Rules.

14.1 Framework and Approach Decision

The Commission has indicated its preferred approach will be to assess the depreciation in PWC Networks' regulatory proposal against the requirements of clause 6.5.5 of the Rules⁷⁰. Power Networks supports this decision.

14.2 Depreciation methodology

Power Networks has revised its depreciation methodology to align it with the standard AER approach. This methodology has been retrospectively applied to the 2009-14 regulatory control period, as well as the future 2014-19 period.

Please note that for the purposes of annual reporting to the Commission, Power Networks has previously applied a methodology that is more aligned with its statutory accrual based straight-line depreciation method.

Code and Rule requirements

Schedule 6 of the Code sets out the approach to be used by the Commission in determining Power Networks' revenue cap. Clause S6.6 requires the regulator to permit the recovery of capital invested in the network over an asset life that is consistent with good electricity industry practice.

Clause 6.5.5(a) of the Rules permits the DNSP to nominate depreciation schedules for network assets, subject to the requirements of clause 6.5.5(b):

- (1) the depreciation profile must reflect the nature of the assets or category of assets over its economic life;
- (2) the sum of the real value of the depreciation of any asset or category of assets over the economic life of that asset or category of assets must be equivalent to the value at which it was first included in the regulatory asset base; and
- (3) the economic life of the relevant assets and the depreciation methods and rates must be consistent with those determined for the same assets on a prospective basis in the distribution determination for that period.

In addition, clause S6.1.3(12) requires the depreciation schedules nominated by the distributor to be categorised by asset class or category driver, together with details of the amounts, values and other inputs used to compile the depreciation schedules.

⁷⁰ Utilities Commission, Framework and Approach Decision Paper, November 2012, p. 71.

The key differences between the AER process and Power Networks' depreciation process previous are outlined in Table 38.

Table 38 – Comparison of depreciation processes

Category	Previous regulatory accounting process	AER process
Asset categories	Align with accounting register > 230 different asset classes	Assets consolidated into 14 RIN categories
Depreciation	Accounting based, with each asset depreciated individually (straight line) based on its commissioning date.	The 14 RIN categories are given an average life, and the sum of the whole asset category is depreciated based on this average life (straight line).
Additions	Assets are recognised when they are commissioned for service, ie WIP is not included.	Assets are recognised on a cash basis, ie. as soon as they are purchased.

14.3 Asset categories

For the purposes of aligning itself with the AER approach, Power Networks has allocated each of its assets to one of the 14 asset classes previously agreed with the Commission. These asset classes are shown in Table 39.

Table 39 – RIN asset categories

Power Networks RIN asset categories
<i>System assets</i>
Transmission terminal stations
Zone substations
Transmission lines
Distribution mains
Distribution substations
Metering
Land and easements
Secondary systems – control, communications and protection
Other
<i>Non system assets</i>
IT and communications
Plant and equipment
Property
Motor vehicles
Other

For the purposes of the 2013 ODRC valuation, SKM were asked to align their work in terms of: asset valuation, asset lives and remaining asset lives, with reference to the same categories.

14.4 Standard and remaining asset lives

As part of the 2013 ODRC valuation, Power Networks sought the expert opinion of SKM in determining the appropriate average life, average age and resultant remaining life to apply to the 14 asset categories as at 30 June 2013. The weighted average values included in the ODRC RFM are included in Table 40.

Table 40 – Standard and remaining asset lives as at 30 June 2013*

Asset category	Weighted average life	Weighted average age	Remaining life
Transmission terminal station	42	24	18
Zone substation	42	28	14
Transmission lines	57	25	31
Distribution mains	56	24	31
Distribution substations	45	21	24
Metering	22	15	7
Land and easements	n/a	n/a	n/a
Secondary systems – control communications and protection	13	10	3
Other	5	2	3
Non-network – IT and communications	12	4	7
Non-Network – Plant and Equipment	14	4	10
Non-Network – Other	5	2	3

* Numbers may not sum due to rounding.

It should be noted that:

- In the case of the “Secondary Systems – control, communications and protection” category, SKM determined that the weighted average age of the assets (29 years) was greater than the weighted average life (13 years). SKM advised that this was due to the existing assets in that category not being representative of their modern equivalents, from which the average life was calculated. However, the AER Roll Forward Model is not designed to accommodate this situation. Accordingly an assumption was made that the remaining life of these assets was three years. Power Networks understands that this is in accordance with AER practice for assets still in use after the end of their expected life.
- In the case of “System capex – Other” and “Non-Network – Other” SKM did not provide any estimates of average life or remaining life. Power Networks has applied the default rates of five years average life and three years remaining life to this category.

14.5 Regulatory depreciation for the 2009–14 regulatory control period

Power Networks has used the RFM to calculate the depreciation expense for the respective asset categories. Note that the depreciation expense is based on the single date of 30 June 2013. The depreciation expense calculation in the RFM is based on straight line calculation of the standard lives at that date.

The regulatory depreciation derived from the RFM is shown in Table 41.

Table 41 – Depreciation for 2009-14 (\$ million, nominal)

Year	2009/10	2010/16	2011/12	2012/13	2013/14
Depreciation – ODRC	-	-	-	-	\$19.32

14.6 Forecast regulatory depreciation for the 2014–19 regulatory control period

Power Networks has used the SKM derived asset lives as the basis for the depreciation rates for the 2014-19 regulatory control period. However the SKM rates are based on the single date of 30 June 2013. The depreciation rates used for the 2009-14 regulatory control period have therefore been derived by Power Networks by using a modified version of the RFM model. Essentially the SKM rates have been adjusted by taking a weighted average of the forecast movement in each of the asset categories, with respect to the capex and depreciation values during the 2013/14 year.

Table 42 contains the regulatory depreciation. This has been derived from the NTRM.

Table 42 – Depreciation for 2014-19 (\$ million, nominal)

Year	2014/15	2015/16	2016/17	2017/18	2018/19
Depreciation – ODRC	\$27.73	\$30.37	\$26.24	\$28.01	\$30.39

The regulatory depreciation forms one of the building blocks to determine Power Networks' revenue, as described in chapter 15.

15 Indicative revenue and pricing for standard control services

In this chapter, Power Networks outlines the calculation of its Annual Revenue Requirement (ARR) for standard control services from the building block components.

On the basis of this ARR, the X factors are derived to provide a smoothed revenue trajectory in real terms.

This Chapter outlines the derivation of allowable annual revenues, prices and the associated X factors, to meet the requirements of Clause S6.1.3(6) of the Rules. The associated detail of all amounts, values and inputs relevant to the calculation is contained in other sections of this Proposal, its attachments and in the NTRM.

Indicative prices for each of Power Networks' tariff classes are also provided in \$/MWh, together with an indication of the proposed impact on small customers' bills.

The methodology utilised to derive these prices is in accordance with the requirements of Chapter 6 of Rules and employs the Commission's NTRM. Power Networks' completed NTRM is provided as Attachment 15 to this Proposal.

Both the revenues and prices presented in this chapter represent indicative numbers only, in that they are based upon:

- The WACC parameters used by the AER for the Aurora determination, whereas the Commission will update Power Networks' final parameters to those observed in the measurement period to be specified by Power Networks and agreed by the Commission; and
- Forecast energy volumes.

Prices are further subject to tariff re-design that Power Networks has recommended as part of its Pricing Proposal at Attachment 12.

Code and Rule requirements

Chapter 6 of the Rules requires the application of a building block approach to the regulation of standard control services.

Part C of Chapter 6 sets out the approach for determining the ARR for each year of the regulatory control period, utilising such an approach.

The building blocks are set out in clause 6.4.3 for each year of the regulatory control period, as follows:

- Indexation of the RAB;
- Return on capital (modified by the Commission to a pre-tax value);
- Depreciation;
- Forecast operating expenditure; and
- Other revenue adjustments arising from the previous regulatory control period.

Taxation expense is not used as a building block component in the pre-tax framework.

Clause 6.5 of the Rules contains the specific requirements for these building block components, which are used to establish an unsmoothed revenue requirement. The resulting price path to deliver this revenue is then smoothed with X factors, in accordance with the requirements of Clause 6.5.9.

15.1 NT Revenue Model

The NTRM has been adapted by the Commission, from the AER's PTRM. The detailed changes to the model involved:

- Substituting a pre-tax WACC for the post-tax WACC in the return on capital calculations; and
- Removal of the taxation building block component.

Power Networks has confirmed, using the PTRM and NTRM, that the revenue outcomes were identical in the case of the Aurora's final determination. The changes to create the NTRM are therefore considered appropriate.

15.2 Building block revenue components and the annual revenue requirement

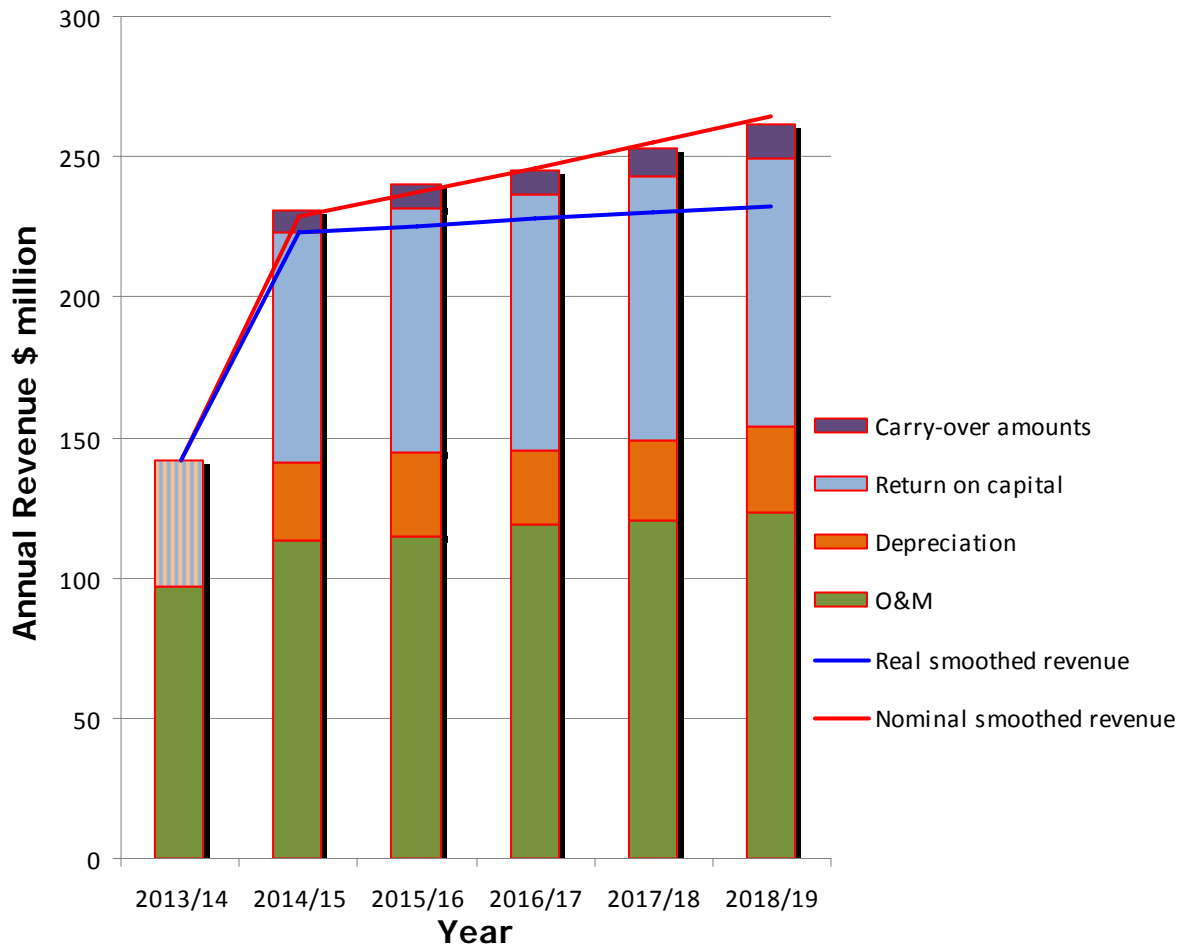
The NTRM has been used to calculate the revenue requirement for standard control services. The building block components and the total revenue are shown in Table 43.

Table 43 – Building block revenue (ODRC) for 2014-19 (\$ million, nominal)

Year	2014/15	2015/16	2016/17	2017/18	2018/19
Return on capital	\$81.85	\$86.97	\$91.10	\$94.07	\$96.11
Depreciation	\$27.73	\$30.37	\$26.24	\$28.01	\$30.39
Operating and maintenance	\$113.63	\$114.39	\$118.92	\$120.69	\$123.25
Carryover adjustment	\$7.37	\$8.23	\$9.18	\$10.25	\$11.44
Unsmoothed revenue requirement	\$230.59	\$239.95	\$245.44	\$253.03	\$261.19

The building block revenue requirements are shown in Figure 19.

Figure 19 – Building block revenue components and smoothed revenue



Of note in Figure 19, whilst the operating and maintenance expenditure is forecast to increase compared with 2013/14, the asset related components of return on assets and depreciation are the major components of the increased revenue requirement. It is apparent that the revenue provided at the 2009 Networks Price Determination fell short of providing sufficient revenues to fund Power Networks' investment in network assets for standard control services.

15.3 X factors for standard control services

The NTRM has also been used to generate the revenue X factors and a smoothed revenue trajectory for the 2014-19 regulatory control period. These quantities are shown in Table 44.

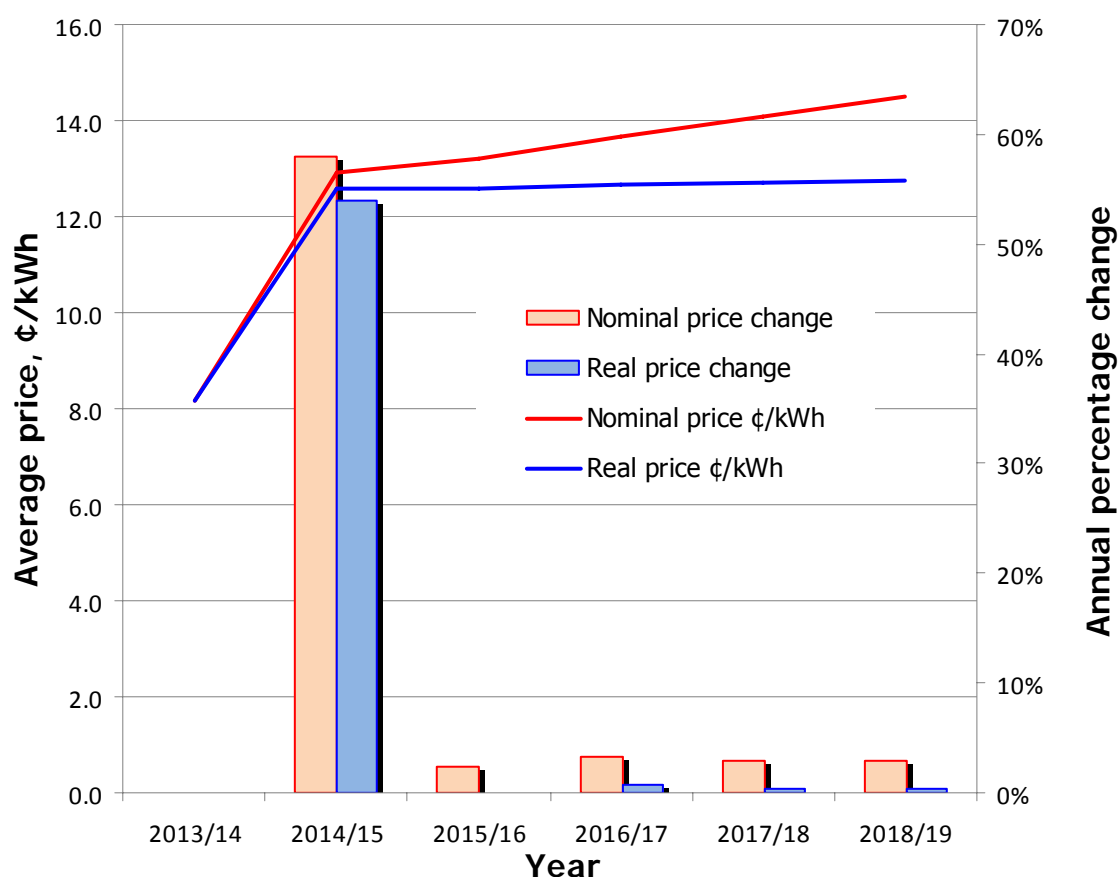
Table 44 – X factors and smoothed revenue for 2014-19 (ODRC) (\$ million, nominal)

Year	2014/15	2015/16	2016/17	2017/18	2018/19
Unsmoothed revenue requirement	\$230.59	\$239.95	\$245.44	\$253.03	\$261.19
X factor	-57.2%	-1.0%	-1.0%	-1.0%	-1.0%
Smoothed revenue requirement	\$229.03	\$237.33	\$245.94	\$254.86	\$264.10

15.4 Indicative prices for standard control services

Figure 20 illustrates the average network price in ¢/kWh, in real and nominal terms. It also illustrates the average change in network price proposed for Power Networks' customers.

Figure 20 – Average price path and price changes



The nominal average price change of 58 per cent in July 2014 is principally required to permit Power Networks to earn a commercial return on its investment in network assets, as noted in section 15.2. Following that change, it should be noted that prices are proposed to increase by a very small percentage and are almost stable in real terms.

15.5 Network Pricing Principles Statement and Pricing Proposal (Draft)

Power Networks' Network Pricing Principles Statement and Pricing Proposal (Draft) is provided at Attachment 12, and the Pricing Proposal Model that supports this document at Confidential Attachment 33. This document will be modified, following the Final Determination on network revenue for 2014/15 by the Commission, to become Power Networks' Pricing Proposal.

This document sets out in detail Power Networks':

- Principles and methods used for establishing the network tariffs to apply to standard control services and alternative control services;
- Proposed pricing strategy for the 2014-19 regulatory control period; and
- Proposed indicative network prices for 2014/15.

This document also demonstrates the compliance of the 2014/15 network prices with the requirements of the Rules and the Code, and the final document submitted to the Commission will demonstrate compliance with the Commission's 2014 Final Networks Price Determination.

This section provides an overview of the proposed pricing for customer classes in 2014/15.

15.5.1 Prices for customer classes

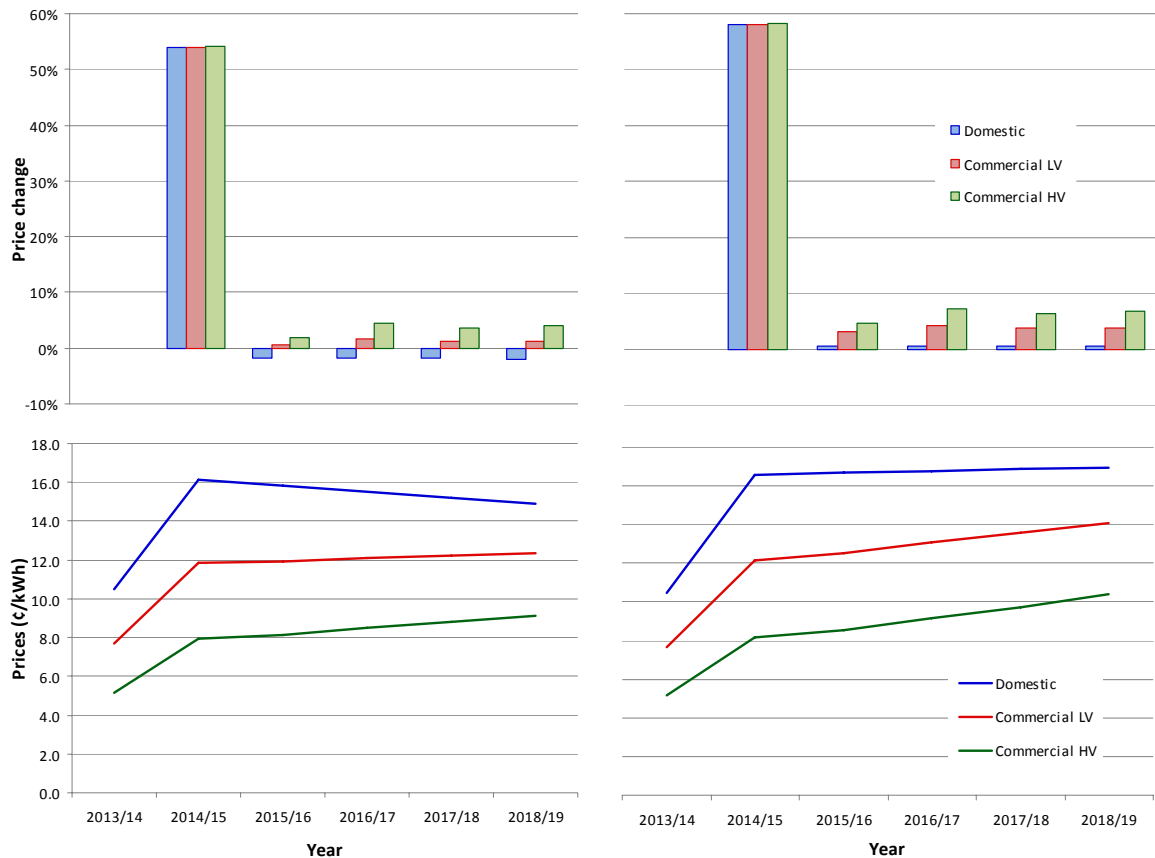
Power Networks has classified its network tariffs into three tariff classes, as follows:

- Domestic;
- Commercial LV (all commercial customers connected to the Low Voltage network and Unmetered supplies); and
- Commercial HV (commercial customers connected to the High Voltage network).

The rationale for the formation of these customer classes is set out in the draft Pricing Proposal at Attachment 12.

The pricing outcome for these three tariff classes is shown in Figure 21. The upper charts display the percentage changes in price throughout the regulatory control period, whilst the lower charts display the proposed network prices in ¢/kWh. The charts on the left are in real terms and the charts on the right are in nominal terms.

Figure 21 – Prices and price changes for tariff classes



In constructing these price paths, the following assumptions have been made:

- The percentage price increase on all tariff components will be the same in 2014/15. In that year, rebalancing of tariffs will be postponed in order to avoid some customers experiencing increases in network prices higher than the initial price change;
- The Commercial HV tariff class is currently recovering less revenue than the cost of supply. The average price for Customers within this tariff class will be increased annually by 1 per cent above the overall revenue trajectory from 2015-19 (a maximum 2 per cent side constraint on tariff class movement is set out in clause 6.18.6 of the Rules);
- The domestic tariff class is recovering more revenue than the cost of supply. It is proposed to decrease the price for this tariff class by 1.0 per cent per annum above the average price movement from 2015-19;
- There are three different customer tariffs within the Commercial LV tariff class: Commercial; Unmetered supplies; and Commercial kVA (with annual consumption greater than 750 MWh). In order to improve the alignment of

these tariffs with their costs of supply, Commercial kVA will be increased by 1.0 per cent per annum. Unmetered supplies decreased by 3 per cent per annum, and Commercial increased by 0.7 per cent per annum.

Further detail on the price paths and the rationale for the price changes is contained in the draft Pricing Proposal. The rebalancing of tariffs is also proposed to take place from 2015-19, to further improve their cost reflectivity.

15.6 Customer impacts

The proposed increase in Network Tariffs is passed on to retailers in the first instance. Retailers can pass on the increased Network Tariffs to contracted customers if they have a pass-through clause in their contracts. However, for customers on pricing orders, retailers can not charge above the regulated retail tariff.

Table 45 below outlines the impacts of the proposed Network Tariff increase for each customer type, based on a sample of customers.

Table 45 – Customer Impacts

Tranche	Customer Type	Average Increase	Increase Range
1-4	Medium to Large Contracted Customers	12 %	7-16 %
5-6	Residential and Small Commercial Pricing Order Customers	No Impact*	

Please note that these impacts are indicative only, as the final 2014-15 Networks Pricing Proposal will be subject to the Commission's Final Networks Price Determination. In addition, the impact on each contracted customer will depend on its individual consumption and demand profile.

Power Networks will submit its final 2014-15 Networks Pricing Proposal following the Commission's Final Networks Price Determination in April 2014.

16 Pass through arrangements

This chapter sets out the pass through arrangements to apply to the 2014-19 regulatory control period. In addition to the pass through events nominated by the Commission in its Framework and Approach Decision Paper, Power Networks proposes some additional pass through events.

16.1 Framework and Approach Decision

The Commission has decided to adopt the same set of pass through provisions for the 2014-19 regulatory control period as it has in the current regulatory period⁷¹. It has decided that it would only consider cost pass through applications if they are the consequence of:

- Change in tax or insurance events;
- Force majeure events;
- Regulatory compliance events;
- Service standard events; or
- Such other events that satisfy the following requirements:
 - the occurrence was not anticipated at the time of the preceding determination or was, while allowable, explicitly excluded from affecting the outcome of that determination on the grounds that the likely impact on Power Networks was unknown or too difficult to quantify at the time, or
 - the occurrence is not a result of actions of Power and Water's board or management or of decisions of the Government in its capacity as owner or shareholder or guarantor of Power and Water.

The Commission has established the current cost pass through materiality threshold of 1 per cent of the annual revenue from standard control services in the financial year in which the event occurs.

Code and Rule requirements

Clause 71 of the Code makes provision for the regulator to revoke or reset a revenue cap if it appears to the regulator that –

- (c) there were extraordinary developments with respect to any one of the key factors identified in clause 68 which, in the opinion of the regulator, were outside the network provider's control.

Clause 68 referred to above contains the principles that the regulator must follow in establishing the revenue cap.

Clause 6.5.10 of the Rules permits the inclusion of pass through events in a regulatory proposal, in accordance with nominated pass through event considerations, set out in the Glossary in Chapter 10.

Clause 6.6.1(a1) permits cost pass through for the following events:

- (1) a regulatory change event;
- (2) a service standard event;
- (3) a tax change event;
- (4) a retailer insolvency event; and
- (5) any other event specified in a distribution determination as a pass through event for the determination.

⁷¹ Utilities Commission, Framework and Approach Decision Paper, November 2012, pp. 81, 82.

16.2 Clarification of the cost pass through threshold

The Commission has stated that it intends to adopt the AER's materiality threshold. This is similar to the current threshold. However, the AER has expressed the threshold level as 1 per cent of the *smoothed forecast* revenue *specified in the final decision* in the years of the regulatory control period that the costs are incurred⁷².

In addition, the Commission is silent on the level of capital expenditure that would be eligible for cost pass through in the event that it was to be incurred. As some pass through events may include both capital and operating cost components, it is important that these costs are considered on an equivalent basis.

For the avoidance of doubt, Power Networks therefore proposes the pass through cost threshold be expressed in the following way:

- **Operating costs:** an additional cost of 1 per cent of the smoothed forecast revenue specified in the Commission's final decision in the years of the regulatory control period that the costs are incurred; and
- **Capital costs:** where the cost to provide the return on and return of the additional capital using the WACC of the Commission's final decision and linear depreciation of the asset over its service life exceeds 1 per cent of the smoothed forecast revenue specified in the Commission's final decision in the years of the regulatory control period that the costs are incurred.

Power Networks accepts that the cost pass through provisions should be symmetrical and that the same cost thresholds would apply if an approved trigger event were to lead to a material reduction in costs.

16.3 Additional pass through events

Power Networks accepts the Commission's decision in its Framework and Approach Decision Paper, in relation to the pass through events that it has nominated. Power Networks also welcomes the Commission's clarification that it regards:

- a structural separation event, if more complete disaggregation of Power and Water's System Operation function or other functions leads to increases in network costs;
 - a new technology event, if a mandated roll out of smart meters or smart grid technology; and
 - an emissions trading scheme event, if costs are impacted by changes to emissions trading arrangements;
- to be covered by the existing categories of pass through events.

⁷² AER, Draft Distribution Determination - Aurora Energy Pty Ltd, 2012/13 to 2016-17, November 2011, p. 292 (confirmed in final decision).

Nonetheless, there are a number of additional events that Power Networks can envisage taking place that are beyond its control that could lead to material cost impacts. Some of these events are based upon the Rules and AER precedent.

Power Networks believes these events should be included, or that the scope of the events nominated by the Commission be further clarified. The additional events are as follows.

Change in tax or insurance event

Power Networks accepts that the pass through of costs for a tax or insurance event as appropriate. However it envisages three related matters that could arise during the regulatory control period and seeks clarification that such events would be included. These events are:

- ***Insurance deductible:*** Power and Water carries insurance for Power Networks' zone substations. Power Networks has also proposed a self-insurance provision for coverage of the 'poles and wires'. The insurance provision for Poles and Wires has been developed on the basis that the first \$50,000 will be deductible and the maximum coverage of \$2.5 million would approximate the pass-through threshold of 1 per cent of revenue. Power Networks seeks confirmation that if a qualifying event larger than this coverage were to lead to draw-down of the insurance provision, the deductible amount would be eligible for pass through.
- ***Liability above insurance cap:*** The self-insurance arrangement described above also has as its basis a maximum liability of \$2.5 million. Power Networks seeks confirmation from the Commission that in the event of damage to the network above the maximum liability of this self-insurance provision, or in the case of liability above the cap of other insurance, that the relevant amount would be eligible for pass through. It should be noted that the AER approved such a pass through provision in the case of the Aurora 2012 determination⁷³.
- ***Insurer credit risk event:*** In the event of an increase in insurance costs as a result of the insolvency of the nominated insurer. The AER also agreed to this cost pass-through event in the case of Aurora.

In each case, the materiality threshold for a pass through event is that proposed in section 16.2.

Retailer insolvency event

The provision for a cost pass through for retailer insolvency is provided for in the Rules. As full retail contestability is now established in the Northern Territory and as retail competition increases, there is an increasing risk to Power Networks that a

⁷³ Ibid, p.264.

retailer may become insolvent. This is a particular risk as the prudential requirements that apply in the NEM (which apply to energy trading obligations) do not apply in the Northern Territory.

Power Networks is therefore seeking that the Commission include provision for a retailer insolvency pass through event in its determination, with the materiality threshold as proposed in section 16.2.

Major network augmentation event

The Rules permits the inclusion of contingent projects within the capital expenditure forecasts, subject to certain conditions including a capital expenditure threshold of \$30 million⁷⁴.

The scale of Power Networks' business is significantly smaller than that of the smallest NEM distributor, ActewAGL⁷⁵. This expenditure threshold is thus considered inappropriately high for Power Networks.

For this reason, Power Networks is instead proposing a cost pass through arrangement for major network augmentation, subject to the materiality threshold proposed in section 16.2. Power Networks can envisage events that may take place in the 2014-19 regulatory control period, including a requirement to vacate the existing Mitchell Street Switching Station site and the requirement to provide supply to a major development, which could potentially exceed this threshold.

The trigger for such an event would be the receipt of notification from Darwin Council to vacate the Mitchell Street site, or unforeseen load growth in an area that would require significant investment such as a new zone substation.

⁷⁴ AEMC, National Electricity Rules clause 6.6A.1(2)(iii). Note that the threshold is the higher of "either \$30 million or 5 per cent of the value of the *annual revenue requirement* for the relevant *Distribution Network Service Provider* for the first year of the relevant *regulatory control period*, whichever is the larger amount". In the case of Power Networks, \$30 million is the larger amount.

⁷⁵ AER, Final decision Australian Capital Territory distribution determination 2009–10 to 2013–14, 28 April 2009, p. 143. Power Networks delivers approximately 60 per cent of the energy and has 2013/14 network revenue around 70 per cent of that of ActewAGL.

17 Attachments

17.1 Glossary

ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Aon	Aon global risk solutions, a company experienced in insurance and risk assessment
ARR	Annual Revenue Requirement
AUD	Australian dollar
AWOTE	Average Weekly Ordinary Time Earnings
CAM	Cost Allocation Method
Capex	Capital expenditure
Capital Contributed Works	Works for which the customer(s) contribute directly to the cost of providing the distribution assets (see also Customer contributions)
CBD	Central Business District
CIPS	Channel Island Power Station
COAG	Council of Australian Governments
Code	Northern Territory Electricity Networks (Third Party Access) Act Schedule - Electricity Networks (Third Party Access) Code
Commission	Utilities Commission, the Northern Territory electricity regulator
Contestability	Customer choice of electricity supplier
CPI	Consumer Price Index
CPM	Carbon Price Mechanism
Current regulatory control period	The regulatory period 1 July 2009 to 30 June 2014
Customer contributions	The value of any network augmentations or extensions funded directly by customers
DAE	Deloitte Access Economics Pty Ltd
Demand	Energy consumption at a point in time
Distribution Network	The assets that link energy consumers to the transmission network
Distribution substation	A substation used for local supply, transforming power from high voltage of 22 or 11 kV to low voltage of 400/230 V

DM	Demand Management, techniques to modify customers' consumption patterns aimed at constraining demand at times of peak network demand
DNSP, Distributor, distribution business	Distribution Network Service Provider
DRP	Debt Risk Premium
DSEP	Distribution System Extension Policy, a policy on charges for extension and connection to the network
ECI	Early Contractor Involvement, a relationship based contract where the contractor works with the principal in the early stages of the project to arrive at a concept design, price and time for delivery of the project
Energeia	Energeia Pty Ltd, a consulting company
EV	Economic Value
FMECA	Failure Mode, Effects and Criticality Analysis, a risk based approach to the management of assets
FRC	Full Retail Competition, Full Retail Contestability
FTE	Full-time employee
GBS	Gas Break Switch, an item of distribution switchgear
GDP	Gross Domestic Product (for Australia)
GIS	Gas Insulated Switchgear (using Sulphur Hexafluoride (SF ₆) as an insulating medium
GCR	Gas Circuit Recloser, an item of distribution switchgear
GOC Act	Northern Territory Government Owned Corporations Act, as in force at 1 February 2011.
GSL	Guaranteed Service Level
GSP	Gross State Product (for the Northern Territory)
HCTS	Hudson Creek Terminal Station
Huegin	Huegin Consulting, a consulting company
HV, High Voltage	Equipment or supplies at voltages of 11 kV or above or the single phase equivalent (6.35 kV)
IBT, Inclining Block Tariff	A network tariff energy rate in which the rate increases as consumption increases
IDMS	Integrated Distribution Management System
IRP	Initial Regulatory Proposal
IT	Information Technology
IEEE	Institution of Electronic and Electrical Engineers (US)
KRA	Key Result Area

kVA, MVA	Kilo-volt amps and Mega-volt amps, units of instantaneous total electrical power demand. See also Power Factor
kVAr, MVAr	Kilo-volt amps (reactive) and Mega-volt amps (reactive) units of instantaneous reactive electrical power demand. See also Power Factor
kW, MW	Kilo-watts and Mega-watts, units of instantaneous real electrical power demand. See also Power Factor
kWh, MWh, GWh	Kilo-watt hours, Mega-watt hours and Giga-watt hours, units of electrical energy consumption
Load duration	The time for which the load at a location exceeds a particular threshold
LPI	Labour Price Index
LRMC	Long Run Marginal Cost
LV, Low Voltage	Equipment or supply at a voltage of 230V single phase or 400V, three phase
MAR	Maximum Allowable Revenue
Marginal Cost	The cost of providing a small increment of service
MED	Major Event Day
MRP	Market Risk Premium
NEL	National Electricity Law - South Australia, National Electricity (South Australia) Act 1996 as at 1 February 2013
NEM	National Electricity Market
NER, Rules	National Electricity Rules
NPD	Network Pricing Determination
NPV	Net Present Value
NTRM	Northern Territory Revenue Model (the AER's PTRM adapted by the Utilities Commission for a pre-tax regulatory framework).
ODRC	Optimised Depreciated Replacement Cost, a method of asset valuation
ODV	Optimal Deprival Value, a method of asset valuation
Off-Ramp	A regulatory decision to re-open a regulatory determination
OHS	Occupational Health and Safety
Opex	Operating expenditure
PB	Parsons Brinckerhoff
Power Factor	A measure of the ratio of real power to total power of a load. The relationship between real, reactive and total power is as follows: $PF = \frac{\text{Real Power (in kW or MW)}}{\text{Total Power (in kVA or MVA)}}$ $\text{Total Power kVAr} = \sqrt{\text{Real Power kW}^2 + \text{Reactive Power kVAr}^2}$
PoE	Probability of Exceedence

PTRM	Post Tax Revenue Model (developed by the AER in accordance with the Rules)
Proposal	Power Networks' Initial Regulatory Proposal
RAB	Regulatory asset base, Regulated asset base
RAMP	Remedial Asset Maintenance Program, a program to identify and correct equipment defects undertaken by Power Networks during the 2009-14 regulatory control period
RBA	Reserve Bank of Australia
RCM	Reliability Centered Maintenance, an approach to the maintenance of assets
RFM	Roll Forward Model for the RAB (developed by the AER in accordance with the Rules)
RIN	Regulatory Information Notice (issued by the Utilities Commission in April 2013)
RIT, RIT-T, RIT-D	Regulatory Investment Test, Regulatory Investment Test for Transmission, Regulatory Investment Test for Distribution
Rules	National Electricity Rules
SAIDI	System Average Interruption Duration Index, a measure of the average duration of customer interruptions
SAIFI	System Average Interruption Frequency Index, a measure of the average frequency of customer interruptions
SCADA	Supervisory Control And Data Acquisition system
SCI	Statement of Corporate Intent, the financial and performance agreement reached between a Government owned corporation and its government shareholder
SCNRRR	Steering Committee of National Regulatory Reporting Requirements (a system of exclusion of outages on major event days)
Side constraint	A limitation in the maximum price change which may be applied to a tariff component or a tariff class in any year
SKM	Sinclair Knight Merz
SoS Code	Electrical Standards of Service Code, published by the Utilities Commission
State Government	The Government of the Northern Territory of Australia
STPIS	The AER's Service Target Performance Incentive Scheme, established subject to the Rules
SWER	Single Wire Earth Return
SWMD	Standard Weather Maximum Demand – an estimate of the demand occurring for average temperature conditions
TAB	Taxation Asset Base (required for Power Networks to implement the AER's PTRM)

TFP	Total Factor Productivity, a system of benchmarking of network inputs and outputs
ToU	Time of Use, a system of pricing where energy or demand charges are higher during peak periods
TPA Act	Northern Territory Electricity Networks (Third Party Access) Act, as in force at 1 August 2012
Transmission Network	The assets that enable generators to transmit their electrical energy to zone substations
T&D	Transmission and Distribution networks
Unmetered supply	A connection to the distribution system which is not equipped with a meter
USD	United States Dollar
VCR	Value of Customer Reliability
WACC	Weighted Average Cost of Capital
WACC Review	AER, Final decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, May 2009
WAPC	Weighted Average Price Cap
WIP	Work In Progress
WPS	Weddell Power Station
Zone substation	A substation used to transform voltage from transmission voltages of 132 or 66 kV to high voltage of 22 or 11 kV

17.2 Certification Statement

**CERTIFICATION OF REASONABLENESS OF KEY
ASSUMPTIONS THAT UNDERLIE CAPITAL EXPENDITURE
AND OPERATING AND MAINTENANCE EXPENDITURE
FORECASTS**

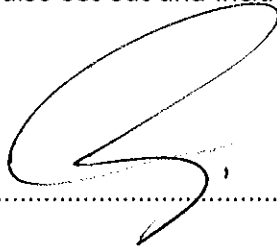
The Directors of the Power and Water Corporation, hereby certify the reasonableness of the key assumptions which:

(1) underlie:

- (a) the proposed capital expenditure forecast as set out and included in PWC Networks' building block proposal; and
- (b) the proposed operating and maintenance expenditure forecast as set out and included in PWC Networks' building block proposal; and

(2) are also set out and included in PWC Networks' building block proposal.

Signed:



.....
Michael BURGESS..... dated the 10th day of September 2013

(Print name)

CHAIRPERSON

17.3 Managing Director's Statutory Declaration

THE NORTHERN TERRITORY OF AUSTRALIA
OATHS, AFFIDAVITS AND DECLARATIONS ACT
STATUTORY DECLARATION

I, JOHN LEONARD BASKERVILLE
50-55 Mitchell Street, Darwin, NT, Managing Director
(name, address and occupation)

do solemnly and sincerely declare as follows:

1. I am an officer, for the purposes of the *Corporations Act 2001*, of the Power and Water Corporation.
2. The Power and Water Corporation is a Northern Territory Government owned corporation established under the *Power and Water Corporation Act* whose shareholder is the Treasurer, as Shareholding Minister, and PWC Networks, the network business division of the Power and Water Corporation is the network provider who provides electricity network access services in the regulated electricity networks of the Northern Territory – Darwin-Katherine, Alice Springs and Tennant Creek -for the purpose of clause 65 of the *Electricity Networks (Third Party Access) Code (NT Access Code)*;
3. The response of PWC Networks regarding the information required to be provided and to be prepared and maintained as specified in the Utilities Commission of the Northern Territory's (**Commission**) regulatory information notice (**Notice**) dated April 2013, is:
 - (a) in accordance with the requirements of the Notice; and
 - (b) is true and accurate, and in all material respects can be relied upon by the Commission to:
 - (i) make the distribution determination to apply to PWC Networks for the 2014-15 to 2018-19 regulatory control period; and
 - (ii) approve the pricing proposals to apply to PWC Networks.

in respect of the regulated electricity distribution services PWC Networks provides in the regulated networks of the Northern Territory – Darwin-Katherine, Alice Springs and Tennant Creek.

This declaration is true and I know it is an offence to make a statutory declaration knowing it is false in a material particular.

Declared at Darwin
(place)

on the 10th day of September 2013

Baskerville
Signature

Before me,

KELVIN STRANGE COMMISSIONER FOR OATHS
(Justice, commissioner for declarations or authorised person) 08 89857211

17.4 Compliance with Code, Rules and RIN

The way in which this regulatory Proposal is compliant with the Code and Rules and the Commission's RIN is set out below.

17.4.1 Code and Rules provisions

Clause 68 of the Code requires the Commission to make a regulatory determination with regard for a number of factors. The information provided in this Proposal is designed to assist the Commission in making its determination. The specific areas of this Proposal that address the matters to which the Commission must pay regard in clause 68 of the Code are set out in Table 46.

Table 46 – Code provisions

Code provision	Reference in this Regulatory Proposal
Demand growth (energy, demand, customer numbers and network length)	Sections 6
Applicable service standards	Section 11
The potential for efficiency gains	Section 10
A cost of capital commensurate with the risks faced by the business	Section 13
The provision of a return on efficient capital investment	Asset base Section 12; Capex Section 8; Depreciation Section 14; and Allowable revenue Section 15.
Recovery of operation and maintenance costs	Section 10.
Changes in taxation liability	None foreseen.
Change in network losses	No material change expected.
The on-going commercial viability of the Power Networks	Section 13 on the appropriate credit risk rating.

In the Framework and Approach Decision paper, the Commission set out those sections of the Rules that would apply to Power Networks in the 2014 Networks Price Determination. Those sections, and the elements of the Proposal that seek to address them, are set out in Table 47.

Table 47 - Rules provisions

Rules provision	Commission recommendation	Reference in this Regulatory Proposal
Part B – Classification of Distribution Services and Distribution Determinations	<p>Partially apply for the 2014 NPD for classification of services and for the form of control mechanism to apply to standard control services.</p> <p>Not applicable for the form of control mechanism to apply to alternative control services - NT Access Code does not authorise the Commission to regulate the prices for these services except in case of dispute or disagreement.</p>	<p>Section 4 and Attachment 4 describe the classification of services into standard control services.</p> <p>The proposed classification of services for alternative control services in Section 4 and Attachment 4 are submitted to the Commission for consideration.</p>
Part C – Building Block Determinations for standard control services	Apply for the 2014 NPD, modified to the extent required to be within Power and Water's capabilities	Sections 6 to 14 and supporting documents describe the basic assumptions and elements of the building block approach in the Rules and demonstrate that expenditure forecasts are prudent and efficient. The calculation of the associated revenues and prices is set out in Section 15.
Part E – Regulatory Proposal	Apply for the NT 2014 Determination, modified to the extent required to be within Power and Water's capabilities	<p>This Proposal has been submitted in accordance with the provisions of clause 6.8.2(c) of the Rules and includes:</p> <ul style="list-style-type: none"> • A classification proposal in Attachment 4; • A building block proposal (Sections 6 to 15 of this document and supporting documents; • Indicative prices for each year of the regulatory control period (Section 15 of this document and indicative Pricing Proposal at Attachment 12); • A connection policy, in the form of the NCCP at Attachment 10;

Rules provision	Commission recommendation	Reference in this Regulatory Proposal
		<ul style="list-style-type: none"> • An identification of those portions of this regulatory Proposal over which Power Networks claims confidentiality; • An overview paper describing the Proposal in plain language, at Attachment 1. • Compliance with the Commission's RIN, as described in Section 17.4.2.
Part I – Distribution Pricing Rules	Apply for the 2014 NPD, modified to the extent required to be within Power and Water's capabilities	A Draft Pricing Proposal has been provided at Attachment 12. Power Networks will submit the Final Pricing Proposal to the Commission after publication of its final determination. The Pricing Proposal conforms with the relevant requirements of clause 6.18 of the Rules.
Part K – Prudential requirements, capital contributions and prepayments	<p>Partially apply for the 2014 NPD for treatment of capital contributions, prepayments and financial guarantees in applying building block.</p> <p>Not applicable for prudential requirements - NT has own Retail Supply Code which sets out prudential arrangements.</p>	<p>Power Networks has proposed the NCCP for the approval of the Commission. This is described in Section 9 and Attachment 10.</p> <p>Prudential requirements are permitted for network connections under section 79(4) of the Code and are provided for in the NCCP at Attachment 10.</p>

17.4.2 RIN provisions

The RIN provisions are set out in Table 48.

Table 48 – RIN provisions

RIN Provision	Reference in this Regulatory Proposal
1.1(a)(i) Classification Proposal	Section 4 – Classification of Services
1.1(a)(ii) Regulated Asset Base Roll Forward Model and Revenue Model	Confidential Attachment 14 - Roll Forward Model Confidential Attachment 15 – NT Revenue Model
1.1(a)(iii) Building Block Proposal	Section 15.2– Building block revenue components and the annual revenue requirement
1.1(a)(iv) Indicative prices	Section 15.4 – Indicative prices for standard control services
1.1(a)(v) Proposed Connection Policy	Attachment 10 – Power Networks Capital Contributions Policy (proposed)
1.1(a)(vi) identification of confidential parts of the Regulatory Proposal	Section 17.6 – Attachments - Confidential documents that form part of the Proposal
1.1(a)(vii) Overview Paper accompanying the Regulatory Proposal	Attachment 1
1.1(c) Cost Allocation Method	Attachment 13 (public version) and Confidential Attachment 28 – Power Networks Cost Allocation Method
1.1(d) Policies, Strategies, Procedures and Consultants Reports used in Regulatory Proposal	Attachments to this Proposal
2. Classification of Services	Section 4 – Classification of Services
3. Control Mechanism	Section 5 – Control Mechanism for standard control services
4. Cost Allocations	Confidential Attachment 28 – Power Networks Cost Allocation Method
5. Capital Expenditure	Section 8 – Forecast Capital Expenditure
6. Operating and Maintenance Expenditure	Section 10 – Forecast operating and maintenance expenditure
7. New Network User Connections and Contributions	Section 8.4 – Forecast network user initiated capital expenditure Section 9 – Capital Contributions
8. Other Entities	Confidential Attachment 26 – System Control Service Level Agreement Confidential Attachment 27– Retail Call Centre Service Level Agreement
9. Pass Through Events	Section 16 – Pass through arrangements
10. Weighted Average Cost of Capital	Section 13 – Weighted average cost of capital

RIN Provision	Reference in this Regulatory Proposal
11. Non-Network Alternatives	Section 8.11 – Demand management and non-network solutions
12. Demand and Customer Number Forecasts	Section 6 – Demand forecasts
13. Unit Costs and Expenditure Escalators	Confidential Attachment 22 - MEA Unit Rate Comparison Section 7 – Real Cost Escalation and CPI
14. Transitional Matters	Section 3 – Transitional issues
15. Alternative Control Services	Section 4.2.2 – Alternative Control Services
16. Network Pricing Principles Statement	Attachment 12 – Networks Pricing Principles Statement and Pricing Proposal (Draft)
17. Capital Contributions Principles Statement	Attachment 10 – Power Networks Capital Contributions Policy (proposed)
18. Indicative Tariff Schedules	Section 15 – Indicative revenue and pricing for standard control services Attachment 12 - Networks Pricing Principles Statement and Pricing Proposal (Draft)

17.5 Non-confidential documents that form part of the Proposal

Attachment 1	Overview of Initial Regulatory Proposal
Attachment 2	Network Connection Technical Code (current)
Attachment 3	Network Technical Code and Network Planning Criteria (proposed)
Attachment 4	Power Networks Proposed Classification of Services
Attachment 5	Network Demand and Customer Connections Forecasting Procedure
Attachment 6	Power Networks Demand Management Procedure
Attachment 7	Power Networks Capital Expenditure Forecast, 2014/15 to 2018/19
Attachment 8	Power and Water Distribution System Extension Policy, May 2006 (current)
Attachment 9	Power and Water 2009 Networks Regulatory Reset Capital Contributions Policy 1 July 2009 to 30 June 2014 (current)
Attachment 10	Power Networks Capital Contributions Policy, March 2013 (proposed)
Attachment 11	Power Networks Maintenance Policy
Attachment 12	Power Networks Pricing Principles Statement and Pricing Proposal (Draft)
Attachment 13	Power Networks Cost Allocation Method v.2.0 (public version)
Attachment 14	Roll Forward Model (ODRC)
Attachment 15	NT Revenue Model (ODRC)
Attachment 16	Roll Forward Model (UC preferred)
Attachment 17	NT Revenue Model (UC preferred)

17.6 Confidential documents that form part of the Proposal

Attachment 18	Regulatory Information Notice - Regulatory Templates
Attachment 18A	RIN - Regulatory Templates - Forecast Capital Expenditure workbook
Attachment 18B	RIN - Regulatory Templates - Forecast Operating and Maintenance Expenditure workbook
Attachment 19	Power and Water's Capital Investment and Delivery Framework
Attachment 20	NT Labour Cost Escalators (DAE)
Attachment 21	NT Material Cost Escalators (SKM)
Attachment 22	SKM 2013 Modern Equivalent Asset Unit Rate Comparison
Attachment 23	Power Networks Capital Expenditure Justifications
Attachment 24	Power Networks Operating and Maintenance Expenditure Justifications
Attachment 25	Huegin Consulting, 2012 Distribution Benchmarking Report
Attachment 26	Power Networks and System Control Service Level Agreement
Attachment 27	Power Networks and Retail (Call Centre) Service Level Agreement
Attachment 28	Power Networks Cost Allocation Method v.2.0 (confidential version)
Attachment 29	Power Networks Asset Strategies Procedure
Attachment 30	Aon Self-insurance Risk Quantification
Attachment 31	Power and Water – Self-insurance arrangement
Attachment 32	SKM 2013 ODRC Valuation
Attachment 33	Power Networks Pricing Proposal Model

2014 NETWORK PRICE DETERMINATION

Initial Regulatory Proposal

HEAD OFFICE

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