REVIEW

Australian Energy Market Commission

DRAFT REPORT

Review of National Framework for Electricity Distribution Network Planning and Expansion

Commissioners

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About the AEMC

The Council of Australian Governments, through its Ministerial Council on Energy, established the Australian Energy Market Commission (AEMC) in July 2005 to be the Rule maker for national energy markets. The AEMC is currently responsible for Rules and policy advice covering the National Electricity Market and elements of the natural gas markets. It is an independent, national body. Our key responsibilities are to consider Rule change proposals, conduct energy market reviews and provide policy advice to the Ministerial Council on Energy as requested, or on AEMC initiative.

Contents

Abbreviations

ACCC	Australian Competition and Consumer Commission
AEMA	Australian Energy Market Agreement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ACG	Allen Consulting Group
CAIDI	Customer Average Interruption Duration Index
CEO	Chief Executive Officer
Commission	see AEMC
CUAC	Consumer Utilities Advocacy Centre
DAPR	Distribution Annual Planning Report
DLF	Distribution Loss Factor
DNSP	Distribution Network Service Provider
DSP	Demand side participation
DUOS	Distribution Use of System
ESCOSA	Essential Services Commission of South Australia
MCE	Ministerial Council on Energy
NEL	National Electricity Law
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NEO	National Electricity Objective
NER	National Electricity Rules
NERA	NERA Economic Consulting
NERA/ACG Report	NERA Economic Consulting (NERA) and Allen Consulting Group (ACG), *Network Planning and Connection Arrangements- National Frameworks for Distribution Networks*, August 2007
NSP	Network Service Provider
NTP	National Transmission Planner
RIT-D	Regulatory Investment Test for Distribution

RIT-T	Regulatory Investment Test for Transmission
RFP	Request for Proposal
Rules	National Electricity Rules
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCO	Standing Committee of Officials
SKM	Sinclair Knight Merz
SKM Background Report	SKM, *Advice on Development of a National Framework for Electricity Distribution Planning and Expansion – Final Report*, 4.0, 13 May 2009.
STT	Specification Threshold Test
TEC	Total Environment Centre
TNSP	Transmission Network Service Provider
TUOS	Transmission Use of System

Summary

The Ministerial Council for Energy (MCE) has directed the Australian Energy Market Commission (Commission) to undertake a review into and propose recommendations for establishing a national framework for electricity distribution network planning and expansion (the Review). This Draft Report sets out our draft recommendations and supporting reasoning for the design of the national framework. It also includes draft specifications which set out in detail our draft recommendations.

In the terms of reference for the Review, the MCE has provided clear direction on which aspects of the current distribution planning arrangements should be included in the national framework and the objectives to be achieved by the national framework. The MCE has requested that the national framework shall:

- require each Distribution Network Service Provider (DNSP) to conduct an annual planning process covering a five year forward looking period and produce an annual planning report informing on its planning process;
- include provisions for DNSPs to conduct robust economic assessment of investment alternatives and provide transparency on the analysis and decisions made by DNSPs; and
- include a dispute resolution process.

Our draft recommendations are consistent with the direction provided by the MCE. The proposed design of the national framework would result in a clearly defined and efficient planning process for distribution network investment and support the efficient development of distribution networks. Appropriate transparency and information regarding DNSPs' planning activities would be provided to allow market participants to make efficient investment decisions and to enable non-network proponents to raise credible alternatives.

We have developed our draft recommendations having regard to the National Electricity Objectives and to achieve a set of principles, which include economic efficiency, transparency, proportionality, technology neutrality and consistency across the NEM. We have also had due regard to the views of stakeholders and have engaged extensively with interested parties, through a series of open workshops and meetings.

Draft Recommendations

Annual planning requirements

The annual planning requirements for the national framework should encompass planning for all assets and activities carried out by DNSPs that would materially affect the performance of the network. The annual planning requirements must be comprehensive across the planning activities undertaken by DNSPs to allow the

benefits to be fully realised. This would include planning activities associated with replacement assets and negotiated services.

Under the proposed national framework, each DNSP would establish and maintain a Demand Side Engagement Strategy. This strategy would involve DNSPs publishing a demand side engagement facilitation process document, establishing and maintaining a database of non-network case studies and proposals, and establishing and maintaining a register of interested parties. This strategy recognises the importance of proactive engagement by both DNSPs and non-network proponents in the development of potential solutions to address system limitations.

The Demand Side Engagement Strategy would be a key component of the national framework. It builds on current industry practice, provides transparency and clarity around the processes adopted by DNSPs, and promotes a constructive working relationship between the business and non-network proponents. The strategy would work together with the Distribution Annual Planning Report and Regulatory Investment Test for Distribution to address a perceived failure by DNSPs to assess non-network alternatives in a neutral manner.

Distribution Annual Planning Report

The national framework would require each DNSP to publish an annual planning report – the Distribution Annual Planning Report (DAPR) by 31 December each year, covering a minimum five year forward planning period starting 1 January the following year.

To increase the transparency and accessibility of the information contained in the DAPR, each DNSP would be required to conduct a public forum on its DAPR within two months of the report being published. The public forum would increase the ability of stakeholders to understand the information contained in the report and to engage directly with DNSPs. The DAPR would be certified by the Chief Executive Officer and a Director or Company Secretary to ensure that the report meets the necessary regulatory requirements, and accurately represents the policies of the DNSP.

The proposed content for the DAPR is similar to the existing jurisdiction reporting requirements. DNSPs would be required to report on capacity and load forecasts (including winter and summer peaks) for sub transmission assets, zone substations and major connection points. The DAPR would also identify any primary distribution feeders which were overloaded (or forecast to be overload within the next two years).

One of key outputs of the DAPR would be the identification and description of any forecast system limitations for sub transmission assets and zone substations. A system limitation should relate to any requirement for distribution investment, which would cover more than network constraints. We propose that DAPRs would include detailed information on system limitations, including: the location and timing of system limitations; analysis of potential load transfer capability; the impact on transmission connection points; and potential solutions that may address the limitation.

DNSPs would also be required to report on their planning methodologies; outcomes from joint planning with transmission network service providers (TNSPs) and other DNSPs; performance standards and compliance against those standards; and a summary of their asset management practices.

Joint Planning

With respect to joint planning, DNSPs and TNSPs should meet regularly to carry out joint planning and work together to identify the most economic solution to a common problem.

We propose that the Regulatory Investment Test for Transmission (RIT-T) be applied to any investments identified through the joint planning process that affect both the transmission and distribution networks or require action by both the TNSP and the DNSP (a joint investment). The application of one regulatory test would be consistent with the economic efficiency principle as it would ensure that the optimal overall solution would be identified. It would also promote transparency as it would provide clarity over the processes adopted and a more efficient assessment process overall.

Regulatory Investment Test for Distribution

We propose that a new project assessment process – the Regulatory Investment Test for Distribution (RIT-D) – replace the current Regulatory Test. The new test would amalgamate the current reliability and market benefits limbs to allow proposed distribution investments to be assessed against both local reliability standards, as well as, their ability to maximise market benefits to the broader market.

The design of the single economic project assessment process for distribution is similar to the project assessment process that has recently been adopted for transmission, the RIT-T. The purpose of the RIT-D would be to identify the distribution investment option which maximises the present value of net economic benefits, subject to meeting deterministic reliability standards. DNSPs would be required to consider all applicable market benefits and costs outlined in the Rules when undertaking the project assessment process. DNSPs would be required to quantify all applicable costs for each credible option, but would have the option to quantify any applicable market benefits, where appropriate.

This approach would be more suited to the characteristics of most distribution investments, as distribution investments typically have more limited market benefits than transmission investments. The values of market benefits which can be achieved through distribution investments are also far smaller and less widespread than those possible in transmission.

RIT-D Threshold

There should be a dollar threshold below which the RIT-D is not undertaken. This is a feature of the current Regulatory Test and would ensure that the administrative burden of the RIT-D remains manageable and proportionate.

We recommend that the threshold for the RIT-D be set at $2 million. This provides an appropriate balance between the benefits of transparency regarding DNSPs' assessment of investment options and decision making processes, and the need to ensure that compliance costs are proportionate and investments proceed in a timely manner. A higher threshold has not been recommended as it would exempt a significant proportion of distribution augmentations from the project assessment process. For smaller scale investments below the $2 million threshold, non-network proponents would be able to investigate and propose alternative investment options through the Demand Side Engagement Strategy.

The cost thresholds for the RIT-D would be subject to periodic review by the Australian Energy Regulator every three years, rather than automatic indexation.

An initial screening test, the Specification Threshold Test (STT), would be applied to all investments which are subject to the RIT-D. The STT would work in conjunction with the cost threshold for the RIT-D to determine the scope of projects which would be subject to the RIT-D and the appropriate process DNSPs must apply for each investment. Investments which do not meet the requirements of the STT would be subject to a fast tracked RIT-D process with more limited reporting and consultation. This is similar to the current arrangements undertaken in South Australia and New South Wales.

Investments related to the refurbishment or replacement of existing distribution assets which are not intended to augment the distribution network, would be exempt from the RIT-D. Negotiated services, urgent and unforeseen investments and customer connections which would not form part of the shared network, would also be exempt. We have also put forward an option for consultation of excluding primary distribution feeders from the RIT-D, in order to reduce the potential for planning delays and to ensure that the requirements of the RIT-D are proportionate to its potential benefits.

Project Specification Stage

The purpose of the project specification stage under the RIT-D would be to require DNSPs to publicly consult on the range of options to meet the identified need and seek comments on any alternative options, both network and non-network. Only investments which meet the requirements of the STT would be subject to the project specification stage of the RIT-D.

We recommend that DNSPs be provided with an opportunity for accelerated consultation on project specification reports if DNSPs are able to demonstrate that they have undertaken prior consultation with non-network proponents outside of the RIT-D process. This would work in conjunction with DNSPs' Demand Side Engagement Strategy and DAPRs, to facilitate and provide incentives for non-network engagement and the investigation of non-network options by DNSPs. This opportunity for accelerated consultation would also place a complementary responsibility on non-network proponents to put forward proposals and engage proactively with DNSPs on an ongoing basis.

Dispute Resolution

The purpose of the dispute resolution process for the national framework would be to provide an accessible and timely mechanism for interested parties to question DNSPs' decision making, and in doing so, provide transparency to DNSPs' decisions and regulatory oversight of their behaviour.

A single dispute resolution process would apply to all investments which are subject to the RIT-D. The dispute resolution process would be limited to a review of the DNSPs' compliance with the Rules in regards to the application of the RIT-D (i.e. a compliance review), rather than a merits review of the DNSPs' decisions during the RIT-D process. It is proposed that interested parties should be able to raise disputes in regards to any aspect of DNSPs' RIT-D processes.

The dispute resolution process would not apply to how DNSPs have conducted their annual planning processes nor how they have prepared their DAPR, as these activities relate to forecasts of future scenarios, rather than commitments to undertake particular actions or investments.

Other Areas for Consideration and Review

The reliability of the distribution network is of critical importance to the quality of the service provided to end customers (disruptions to distribution networks are responsible for approximately 90% of the duration of interruptions to customers). Therefore it is important to note that this Review is proposing recommendations on a component of the overall framework which governs how DNSPs plan and invest in their networks. A number of other aspects and arrangements also influence network planning and the level of reliability, and the role of the national framework needs to be considered within the overall regulatory regime for distribution planning.

This Review will benefit the performance and reliability of distribution networks through increasing information transparency; promoting more efficient investments by both DNSPs and end-customers; and by providing a level playing field across the NEM. However, as shown in Table 1, significant of aspects of the overall regulatory regime will continue to be set on a differential basis at a jurisdictional level.

Chapter 6 of the Draft Report comments on how reforms on these other aspects of the broader regulatory regime would contribute to ensuring safe, reliable and efficient networks, and complement the Review recommendations and the arrangements for transmission. We suggest that further work should be pursued in relation to the processes for setting distribution reliability standards, measuring distribution reliability performance, and the asset management practices of distribution businesses.

Table 1: Framework for Distribution Planning in the NEM

Planning Requirement	Jurisdictional Obligation	National Obligation
Annual Planning	Currently jurisdictionally based	Review to recommend national obligations
Project Assessment	Currently mix of jurisdictional and national obligations	Review to recommend national obligations
Reliability Standards	Jurisdictional obligations	National obligations in Schedule 5.1 of the NER
Revenue Determination		National obligations in Ch 6 of the NER
Asset Management	Jurisdictional obligations in NSW, Qld, VIC	
Service Incentive Schemes	Currently jurisdictionally based	National obligations in process of implementation
Customer connections & capital contributions	Currently jurisdictionally based	MCE SCO review to recommend national obligations

Next Steps and Consultation on the Draft Report

We invite stakeholders to make submissions on the draft recommendations and specifications by 13 August 2009. A public forum on the Draft Report will be held on Wednesday, 5 August 2009 in Melbourne. Interested parties wishing to attend the public forum are invited to register by 24 July 2009 by completing a registration form on the Commission's website at: www.aemc.gov.au.

We will submit our final report to the MCE by 30 September 2009.

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1 Introduction

The Ministerial Council of Energy (MCE) has directed the Australian Energy Market Commission (Commission) to conduct a review into the current arrangements for electricity distribution network planning and expansion in the National Electricity Market (NEM) and propose recommendations to assist the establishment of a national framework for these arrangements (the Review).

This Draft Report sets out for consultation the Commission's draft recommendations for the national framework. It discusses the various components of the national framework and provides the supporting reasoning behind our draft recommendations. Also attached are draft specifications which set out the proposed design for the national framework (see Appendices A & B). The purpose of these specifications is to explain in detail the design of the proposed national framework.

We have developed the draft recommendations to achieve the MCE objectives and have taken into consideration stakeholder comments received on our Scoping and Issues Paper and provided during the two stakeholder workshops we held during this Review.[1]

This Chapter describes the MCE's terms of reference of the Review and discusses the context of, and the approach taken, for the Review. It also sets out a series of design principles, consistent with the National Electricity Objective (NEO), against which we have tested our draft recommendations. Finally, the Chapter discusses the next steps for the Review, implementation issues for the national framework, and the process for making written submissions on this Draft Report.

1.1 The Review Framework

The regulatory arrangements governing distribution network planning are contained in two places; Chapter 5 of the National Electricity Rules (Rules or NER) and also in jurisdictional instruments. These two regimes do not operate in a complementary way and, as a result, the obligations of Distribution Network Service Providers (DNSPs) can be unclear. Also, the jurisdictional arrangements can differ significantly in both their objectives and application.

There is a view that the lack of consistency and transparency within the current arrangements impedes efficient investment by both Network Service Providers (NSPs) and market participants and creates a bias against the consideration of non-network alternatives. The objective of this Review is to develop a national framework that addresses these issues.

[1] AEMC, 2009, Review of the National Framework for Electricity Distribution Network Planning and Expansion Scoping and Issues Paper, 12 March 2009, Sydney.

1.2 Terms of Reference for the Review

Through its terms of reference, the MCE has provided clear prescription on the objectives of the national framework and has specified the various arrangements which will contribute to the framework.[2] The MCE terms of reference states that the national framework for distribution network planning shall include the following:

- a requirement on DNSPs to perform an annual planning process;
- a requirement on DNSPs to produce and make publicly available an annual planning report which has a five year planning horizon. At a minimum the annual plan must forecast distribution network constraints;
- a requirement for DNSPs to undertake a case by case project assessment process to identify the most economic option when considering network expansions and augmentations. This process is to be triggered using appropriate thresholds; and
- a dispute resolution process.

The MCE's terms of reference also provide guidance on the required characteristics of the national framework, including that:

- DNSPs have a clearly defined and efficient planning process which provides certainty in relation to the approval of network expansion and augmentation to maintain the reliability of the electricity supply to consumers.
- DNSPs develop the network efficiently. This includes addressing a perceived failure by DNSPs to look at non-network alternatives (such as embedded generation, energy efficiency and conservation measures) in a neutral manner when making distribution augmentation assessments.
- Appropriate information transparency to allow:
  - network users, including distributed generators, to plan where best to connect to the network and provide an appropriate regulatory environment to facilitate this;
  - network users to understand how the timing of connection might affect connection charge arrangements, to the extent which connecting users contribute to upstream augmentation requirements; and
  - efficient planning by parties that may offer alternative, more cost-effective solutions to network augmentations to address emerging constraints.
- Ensure a level playing field for all regions in terms of attracting investment and promoting more efficient decisions.

[2] The terms of reference for the Review is available at www.aemc.gov.au.

- Reduce the regulatory compliance burden for participants operating in more than one region in the NEM.

1.3 Context for Distribution Planning

It is important to note that this Review is assessing and proposing recommendations on a component of the overall framework which governs how DNSPs plan and invest in their networks. Other aspects and arrangements outside the scope of this Review also have an influence on network planning. The development of the national framework for distribution network planning and expansion needs to be considered within this broader regulatory regime.

This section discusses the interactions with various other regulatory arrangements, which have an impact on distribution planning. As shown in Table 1, certain aspects of the broader regulatory regime are being transitioned from jurisdictional to national arrangements, while other aspects will continue to be set at a jurisdiction level.

Table 1: Framework for Distribution Planning in the NEM

Planning Requirement	Jurisdictional Obligation	National Obligation
Annual Planning	Currently jurisdictionally based	Review to recommend national obligations
Project Assessment	Currently mix of jurisdictional and national obligations	Review to recommend national obligations
Reliability Standards	Jurisdictional obligations	National obligations in Schedule 5.1 of the NER
Revenue Determination		National obligations in Ch 6 of the NER
Asset Management	Jurisdictional obligations in NSW, Qld, VIC	
Service Incentive Schemes	Currently jurisdictionally based	National obligations in process of implementation
Customer connections & capital contributions	Currently jurisdictionally based	MCE SCO review to recommend national obligations

Reliability Standards

The security of supply and reliability standards, which are set out in jurisdictional instruments and Schedule 5.1 of the Rules, will underpin how the annual planning processes are undertaken by the DNSPs. The Sinclair Knight Merz (SKM) Background Report, which was released following the publication of our Scoping and Issues Paper, detailed the various jurisdictional reliability criteria and standards and showed a mixture of deterministic and probabilistic criteria are currently applied.[3] It is noted that the form, function and the processes for setting the criteria, in addition to how a DNSP interprets and complies with the criteria, vary significantly across the NEM.

There are appropriate reasons as to why reliability standards should differ at a jurisdictional level. Jurisdictional differences are required to reflect regional issues and variations in operating environments. However, divergent arrangements and processes in the setting of reliability standards may affect the achievement of the desired objectives for the national framework. The current arrangements will affect the level of transparency of the planning arrangements and the ability of market participants, both non-network proponents and large customers, to operate on a NEM wide basis. There is also a concern relating to the interaction of transmission planning and distribution planning, given the volume of investments that are jointly planned.

Issues relating to the current jurisdictional reliability standards are further explored in Chapter 6 of this Report. Given the importance of the role of security and reliability standards in distribution planning, we suggest that a further review is undertaken to assess the materiality of these issues.

Revenue Determination framework

The process for the approval of expenditure for distribution networks and the regulatory incentives provided to DNSPs are set out in Chapter 6 of the Rule. These arrangements have a significant influence DSNPs' planning processes and investment decisions. The regulatory requirements provided under the national framework should support these incentives on DNSPs, especially in regard to the pursuit of non-network alternatives. We are assessing whether the current arrangements act as a barrier to the efficient level of demand side participation being achieved in the NEM in our Demand Side Participation (DSP) Review.[4]

Future reforms in distribution planning

The arrangements governing and affecting investment in, and the operation of, electricity distribution networks are under going significant reform. Government policy initiatives in response to climate change – including emissions trading, the expanded mandatory renewable energy targets and the rollout of smart meters – will create new challenges for network service providers. Also, electricity distribution systems are evolving towards becoming "active networks" that interact with both demand and supply sides. Industrial combined heat and power, distributed

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[3] Sinclair Knight Merz, *Advice on Development of a National Framework for Electricity Distribution Planning and Expansion – Final Report*, 4.0, 13 May 2009.

[4] AEMC, 2009, *Review of Demand Side Participation in the National Electricity Market*, Stage 2: Draft Report, 29 April 2009, Sydney.

renewable generation, and micro-generation units installed by households equipped with smart meters will all pose new challenges to distribution networks to innovate and adopt new technologies.

We have developed our draft recommendations with those reforms in mind to ensure that the national framework is robust for the long term and supports the ongoing reforms in the industry.

Related AEMC work

We are also conducting a number of reviews and considering Rule change requests that relate to the arrangements for distribution network planning. Where relevant, we will manage the various interactions between this Review and other work-streams as we conduct our assessment of the appropriate national framework. A summary of the current reviews and Rule changes that relate to the national framework are outlined in Appendix C.

1.4 The Commission's Approach to the Review

1.4.1 Process of the Review to Date

The Review commenced with the publication of a Scoping and Issues Paper on 12 March 2009. The Scoping and Issues Paper sought views on the scope and key design issues for the national framework and, in particular, on what aspects of the current jurisdictional requirements should be maintained and what features of the transmission planning framework were appropriate for distribution. 19 submissions on the Scoping and Issues Paper were received. AEMC staff also conducted a series of meetings with interested parties following the publication of the Scoping and Issues Paper.

On 27 May and 4 June 2009, AEMC staff held stakeholder workshops on a possible design for the national framework. The purpose of these workshops was to provide interested parties with an opportunity to comment on a proposed "high level" design and contribute to the development of the national framework by discussing a number of key design issues. The workshops also allowed AEMC staff to test proposals on how the framework should be applied. A number of group break out sessions were conducted during the workshops where participants were asked to address and develop proposals on individual design issues for the framework. Over 40 stakeholders attended each of the workshops. The Stakeholder Workshop Paper and the presentations given by AEMC staff during the workshops, are available on our website at: www.aemc.gov.au.

Prior to the workshops, we published the SKM Background Report.[5] This report was developed as reference material for the Review and provides a summary of the processes currently undertaken by electricity DNSPs in the NEM when planning and augmenting their networks.

[5] SKM Background Report, op. cit.

1.4.2 Principles for the Review

In developing our draft recommendations for a national framework for distribution network planning, we are required to have regard to the NEO in the National Electricity Law (NEL). The NEO states:

> 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.[6]

Consistent with the NEO, we have developed a set of principles for the Review to guide the development of recommendations for the national framework. These principles were developed after taking into account the direction provided by the MCE in its terms of reference and stakeholder comments on the Scoping and Issues Paper.

The principles for the Review are as follows:

1. **Economic Efficiency** – the national framework must promote efficient investment in distribution networks. The framework should provide for an assessment of all relevant economic benefits associated with an investment;

2. **Transparency** – the national framework must ensure that sufficient information is made available to enable network users to make efficient decisions and non-network providers to propose feasible and credible alternatives to address network problems. The planning process must be clear, readily understandable and open to interested parties;

3. **Proportionality** – the costs arising from the processes and regulatory requirements under the framework must be proportionate to the benefits. The extent of information provided and consultation process must strike the appropriate balance;

4. **Technological Neutrality** – the national framework should be technologically neutral, and not be biased towards network solutions where non-network options can provide a comparable level of reliability;

5. **Consistency across the NEM** – the framework must ensure a level-playing field for all regions in terms of attracting investment and promoting more efficient decisions. This should reduce the regulatory compliance burden for participants operating in more than one region;

[6] Section 7, National Electricity Law.

6. **Fitness for purpose, reflecting local conditions** – whilst accepting that consistency across the NEM is paramount, the framework should, where necessary, allow for differences in operating environments and network conditions across the DNSPs;

7. **Building on existing jurisdictions requirements -** the national framework must properly incorporate the existing jurisdictional requirements and ensure that it does not result in any deterioration in the robustness and accountability of distribution planning compared to the current arrangements; and

8. **Consistency with transmission planning framework -** where appropriate, the national framework for distribution should be consistent with the arrangements for transmission planning. This is important in ensuring efficient joint planning of transmission and sub transmission networks and the delivery of an appropriate level of reliability and service quality at each transmission–distribution connection point.

1.5 Structure of the Draft Report

The remainder of the Draft Report contains the draft recommendations regarding the various aspects of the national framework and is structured as follows:

- Chapter 2 – Annual Planning Process
- Chapter 3 – Annual Reporting Requirements
- Chapter 4 – Regulatory Investment Test for Distribution (RIT-D)
- Chapter 5 – Dispute Resolution Process
- Chapter 6 – Further Observations on the Framework for Distribution Planning
- Appendix A – Draft Framework Specifications: Annual Planning and Reporting Requirements
- Appendix B – Draft Framework Specifications: Regulatory Investment Test for Distribution and Dispute Resolution Process
- Appendix C – Related AEMC Reviews and Rule changes
- Appendix D – Comparison of Jurisdictional Reporting with the Draft Framework
- Appendix E – Design of the RIT-D and Dispute Resolution Process Flowcharts
- Appendix F – Distribution Reliability in the NEM

1.6 Process and Next steps

The next steps for the Review are set out below:

Milestone	Date
Public Forum on the Draft Report	5 August 2009
Submissions due on Draft Report	13 August 2009
Final Report and draft Rules submitted to MCE	30 September 2009

1.6.1 Lodging submissions on the Draft Report

Submissions on the Draft Report are requested by **5 pm, Thursday, 13 August 2009**. Submissions should contain the reference **"EPR0015"** in the subject heading. Submissions may be sent electronically through the AEMC's online lodgement facility at www.aemc.gov.au

Or in hardcopy to:

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

1.6.2 Registration for the public forum

The Commission will hold a public forum on the Draft Report on Wednesday, 5 August 2009 in Melbourne. The purpose of the public forum is to:

- allow the Commission to present its draft recommendations as contained in the Draft Report; and
- give stakeholders and interested parties the opportunity to ask questions of the Commission and discuss issues of concern prior to finalising their written submissions on the Draft Report.

Stakeholders wishing to attend the public forum are invited to register by Friday, 24 July 2009. Stakeholders can register for the public forum by completing a registration form on the Commission's website at: www.aemc.gov.au.

Further details on the public forum, including an agenda for the forum, will be published shortly on the Commission's website.

1.7 Implementation of the National Framework

Following the submission to the MCE of the Final Report and proposed Rule amendments in September 2009, the MCE will consider the recommendations and decide upon the appropriate design for the national framework.[7] The national framework would then be implemented through a formal Rule change process.

The national framework is not intended to result in the duplication of planning arrangements, nor is it being designed to work in parallel with the current jurisdictional requirements. Therefore, we assume that the existing jurisdictional arrangements relating to the project assessment process and annual planning and reporting requirements, will be rolled back once the national framework is in place. Regarding the annual planning process and reporting requirements, the draft specifications provide flexibility for jurisdictions to include additional reporting and planning requirements, however, this should occur on an exemption and limited basis.

The introduction of the national framework may result in significant changes to DNSPs' and other market participants' operational practices. It would also require the Australian Energy Regulator (AER) to develop a new Regulatory Investment Test for Distribution (RIT-D) and supporting guidelines. Given this, we propose that a one year transition period should apply before the RIT-D commences, once any Rule changes have been made.

Regarding the annual planning process and reporting requirements, we consider that DNSPs would need at a minimum 9 months before the publication date of the first Distribution Annual Planning Report (DAPR), to comply with the new requirements. Hence for the first DAPR to be published by 31 December 2010, the Rules for the national framework would need to be made by 1 April 2010.

[7] The Final Report shall also discuss the relevant civil penalties provisions for the national framework.

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2 Annual Planning Process

This Chapter sets out the draft recommendations on the national annual planning process for distribution. It describes the proposed annual planning process, including proposed Demand Side Engagement Strategy. This is a new obligation which aims to provide transparency on how DNSPs assess and consider non-network alternatives, and promote a clear and transparent process for DNSPs to engage with non-network proponents.[8] Requirements for the joint planning activities undertaken by Transmission Network Service Providers (TNSPs) and DNSPs are also discussed.

Summary of draft recommendations

1. Each DNSP would carry out an annual planning process covering a minimum forward planning period of five years. The planning process would apply to all distribution network assets and activities undertaken that would be expected to have a material impact on the distribution network.

2. Each DNSP would be required to use reasonable endeavours to engage with non-network proponents and consider non-network alternatives.

3. Each DNSP would be required to establish and implement a Demand Side Engagement Strategy.

4. Each DNSP would be required to publish a Distribution Annual Planning Report by 31 December, which must be certified by the Chief Executive Officer and a Director or Company Secretary, and conduct a public forum.

5. DNSPs and TNSPs that operate in the same jurisdiction would be required to meet on a regular basis and undertake joint planning where there are issues affecting both networks.

6. The Regulatory Investment Test for Transmission would apply to investments identified through the joint planning process.

2.1 Purpose of Annual Planning

The objective of annual planning is to identify possible future issues that could negatively affect system performance to enable DNSPs to plan for and adequately address such issues in a sufficient timeframe. The purpose of having a national annual planning process is to ensure that all DNSPs conduct a clearly defined, common and efficient planning process. Such a process would provide certainty in relation to the approval of network expansion and augmentation projects to maintain the reliability of electricity supply to end-use-customers. In addition, the annual planning framework would ensure that DNSPs develop the network efficiently and

[8] The "Demand Side Engagement Strategy" replaces the "Non-network Strategy" outlined in the Workshop Paper.

consider non-network alternatives in a neutral manner when undertaking augmentation assessments.

2.2 Scope and Requirements of the Annual Planning Process

Draft recommendation

The scope of the annual planning process would require DNSPs to carry out an annual planning process covering a minimum forward planning period of five years for distribution and sub transmission networks (and 10 years for any transmission assets operated by the business).

The annual planning process would apply to all distribution network assets and activities undertaken that would be expected to have a material impact on the distribution and sub transmission networks in the forward planning period (which would include negotiated services and replacement activities).

DNSPs would be required to prepare forecasts, to the best of their ability, of maximum demands across networks assets, after considering the impact of customer connections, consumption, and the level of embedded generation at the relevant asset level. Given these forecasts, DNSPs would be required to identify system limitations and possible options to address such limitations.

The annual planning process would require DNSPs to undertake, at a minimum, forecasts and identify system limitations including taking into consideration non-network alternatives. DNSPs would also be required to undertake the annual planning process in a manner consistent with its asset management policies.

Reasoning for draft recommendation

One of the objectives of the national planning framework is to ensure DNSPs effectively plan over a reasonable period in order to identify and address potential problems on their distribution networks. This helps to maintain the required level of service to their customers. Therefore to achieve this objective, planning should encompass planning for all assets and activities carried out, which would materially affect the performance of the network. That is, the planning process undertaken must be comprehensive to ensure that DNSPs make efficient planning decisions across their networks. This will allow the benefits of having a national process to be fully realised. For these reasons, the annual planning process for the national framework should not be limited to the planning of the augmentation of the shared network, but should also include planning activities associated with other assets, including replacement assets and negotiated services.

The MCE has stated that the planning process shall have a five year planning horizon. To reflect this, the draft recommendations state that a minimum five year planning horizon would apply for distribution and sub-transmission assets.[9] To

[9] It is proposed that a sub transmission asset is defined as a *substation* or switching station connected with a primary voltage 33kV or greater and is not a *transmission* asset.

maintain consistency with the transmission planning arrangements, DNSPs would be required to apply a 10 year planning horizon for any transmission assets which they operate.

By setting out the minimum requirements of the annual planning process, the draft recommendations apply the consistency principle by clarifying the factors that would be taken into consideration by DNSPs during planning. Further, the draft recommendations were developed giving consideration to the existing jurisdictional requirements for planning and reporting to ensure the integrity of the current provisions are maintained.

To recognise the differences in the planning methodologies and the relative importance in planning for each asset and service class, the draft recommendation provides for flexibility to allow any specific jurisdiction and geographical requirement to be met. This would also be consistent with the fit for purpose principle, to allow for differences in operating environments and network conditions across DNSPs.

A key factor in any planning process is the credibility and accuracy of forecasts. We have stated that DNSPs must prepare forecast to the best of their ability without any specific provisions on how DNSPs should model the future and determine such forecasts. Given the existing level of planning expertise within DNSPs and the incentives and obligations on DNSPs to plan accurately, placing detailed requirements on forecasting would not be consistent with the principle of ensuring that the national framework is proportionate.

The planning arrangements for the national framework consist of the annual reporting process, the RIT-D process, and the Demand Side Engagement Strategy. It is through the interaction of these three components that the intended purpose and objectives of the national framework is best achieved. For example, non-network proponents would be able to review the annual planning report to evaluate potential options that could be discussed with DNSPs.

The Demand Side Engagement Strategy would facilitate further information exchange and engagement as well as facilitate the development of any proposals by non-network proponents. The RIT-D would then provide the formal consultation and assessment process, which would recognise any prior consultation conducted by DNSPs under the Demand Side Engagement Strategy. The effective utilisation of the planning framework should minimise costs in the long run by providing a clear process to ensure all feasible solutions are considered effectively at the appropriate time. This would allow the most effective solution to a problem to be identified. The need to have a balanced and holistic approach was also noted by stakeholders.[10]

10 See, for example, ActewAGL's submission to the Scoping and Issues Paper.

2.3 Demand Side Engagement Strategy

Draft recommendation

DNSPs would be required to use reasonable endeavours to engage with non-network proponents and consider non-network alternatives. DNSPs would also be required to establish and implement a Demand Side Engagement Strategy, encompassing three components:

1. Demand Side Engagement Facilitation Process Document (the facilitation process document);

2. Public database of proposals/case studies; and

3. Register of Interested Parties.

Reasoning for draft recommendation

Under the economic efficiency principle, the national framework must promote efficient investment in distribution networks. This requires DNSPs to consider all feasible options for network development, including allowing potential non-network proponents to engage with the development process.

The Demand Side Engagement Strategy recognises the importance of the proactive engagement of both DNSPs and non-network proponents in developing potential solutions. Stakeholders have noted that currently it can be difficult for non-network proponents to engage with DNSPs at an appropriate stage of the planning process. In addition, there is limited transparency on how DNSPs assess and consider non-network proposals. The Demand Side Engagement Strategy addresses these issues by building on industry best practice to provide transparency and clarity around the processes adopted by DNSPs. In addition, it promotes the engagement of non-network proponents, providing improved opportunities for non-network proponents and DNSPs to interact productively, and providing the basis for developing on-going working relationships. It is noted that a number of DNSPs currently carry out this level of engagement with non-network proponents.

The proposed framework would not preclude a DNSP ,itself, from proposing non-network alternatives. As discussed in Chapter 1, incentives for DNSPs to undertake non-network solutions are impacted by other regulatory and commercial drivers. The planning framework needs to operate with and compliment the other drivers that currently exist.

Demand Side Engagement Facilitation Process Document

The draft recommendations would require DNSPs to publish a "Demand Side Engagement Facilitation Process Document" (the facilitation process document), to provide clarity and transparency to the processes adopted by DNSPs in assessing non-network alternatives and interacting with non-network proponents. This facilitation process document would detail the processes that are adopted by DNSPs in their management and consideration of non-network proposals. For the facilitation process document to be useful and meet the objectives of introducing the

Strategy, it needs to provide relevant information that would of assistance to non-network proponents. The document should provide benefits to non-network proponents by identifying matters to be addressed in developing any non-network proposals.

The draft recommendations propose the type of information which we considered to be of benefit and able to be provided by DNSPs at reasonable cost. Our suggested material for inclusion in the document is:

i. the process which the DNSP follows to develop, investigate, assess and report on potential non-network solutions;

ii. the process which the DNSP follows to engage and consult with potential non-network proponents to determine their level of interest and ability to participate in the development process;

iii. an outline of the process which the DNSP follows to negotiate with non-network proponents to further develop a potential solution;

iv. an outline of the information a non-network proponent is to include in a non-network solution proposal;

v. an outline of the criteria that a potential non-network proponent should meet or consider in any offers or proposals;

vi. an outline of the principles that the DNSP considers in developing the payment levels for non-network solutions;

vii. a reference to any applicable incentive payment schemes for the implementation of non-network solutions and whether any specific criteria is applied by the DNSP in its application and assessment of the scheme;

viii. sources of relevant, publicly available information that non-network proponents may access;

ix. how non-network proponents may contact the DNSP to request additional information or register as an interested party;

x. the process, including the information that would be provided, for updating the parties registered on the Register of Interested Parties;

xi. the DNSP's contact details; and

xii. the methodology to be used for determining avoided Customer TUOS charges, in accordance with clause 5.5 and clause 5.6.2(k1) of the Rules.

We seek comments on whether the proposed content of the facilitation process document provides useful information and can be provided by DNSPs at reasonable cost.

Although publishing such a document has generally been supported by all stakeholders, some DNSPs consider that the document should not include details relating to proposals and the criteria that are used for developing payment levels (specifically, points iv to vii above), as these details would vary according to each proposal.

However, these aspects of the facilitation process document would form the key components that non-network proponents would consider in preparing proposals and assessing the economic feasibility of potential alternatives. This would be consistent with the principles of transparency and economic efficiency, as clarifying these processes would provide greater certainty to potential investors and non-network proponents. The requirements for the facilitation process document also give consideration to, and are consistent with, the principle of allowing for differences in operating environments and network conditions.

The Total Environment Centre (TEC) noted that the implementation and delivery of the strategy were important considerations and suggested that the AEMC develop explicit protocols for the strategy.[11] At this stage, we consider that there is no need for further specification on the content of the document. DNSPs should be given the flexibility to comply with the provisions and to maintain the document, in a way which reflects their own circumstances and interactions with non-network proponents. However, we request comments on whether TEC's suggestion for establishing explicit protocols would be beneficial.

We seek comments on whether explicit protocols for the Demand Side Engagement Facilitation Process Document would be beneficial.

The implementation and delivery of the Demand Side Engagement Strategy are important considerations. The facilitation process document is expected to be subject to on-going development and refinement as DNSPs learn and improve their operational practices and, for these reasons, the draft recommendations require the facilitation process document to be reviewed at least once every three years. It would be updated to reflect changes and developments in the requirements of stakeholders as DNSPs and as non-network proponents learn from their experiences.

Public database of proposals/case studies

Each DNSP would be required to establish and maintain a public database containing proposals that had been received and case studies providing examples of the project proposal and assessment process.[12] This requirement achieves the transparency principle, where information that would enable non-network providers to make efficient decisions and propose feasible and credible options would be more readily available. Overall efficiency for non-network proponents operating in more than one jurisdiction may also be improved where actual examples of proposals

[11] TEC noted in its submission to the Workshop/Workshop Paper, p.3, that "At the DNSP level, the critical issue is not one of *strategy* but of *implementation* and *delivery*. This requires a focus on performance, not just strategy… the AEMC should develop its own Non-Network Strategy and set explicit protocols for all networks in the procurement of non-network solutions."

[12] Proposals and case studies to be included in the database should demonstrate and exemplify proposals received by DNSPs as well as the process with which they were assessed and considered by the DNSPs.

would be made available to allow the jurisdictional differences to be better understood.

We consider that DNSPs should be allow to select from their existing materials information that, based on their experience, would promote the engagement with non-network proponents and set out effective examples. This provision promotes with the proportionality principle as it would provide benefits to stakeholders by ensuring that actual examples on proposals are available, whilst minimising the costs of DNSPs. It is expected that the database would contain examples of proposals that were successful as well as proposals that were not successful. In selecting items to be published in the database, DNSPs should not breach any confidentiality provisions or publish any commercially sensitive information.

Register of interested parties

The draft recommendations require each DNSP to establish and maintain a register of interested parties. DNSPs would be required to advise those on their list of registered parties of the publication of any relevant planning information. This would include the annual planning reports and any reports that are published under the RIT-D. In addition, DNSPs may wish to publish updates relating to specific projects or network issues. This provision would provide for interested parties to be advised of relevant information in a timely manner.

2.4 Publication of Distribution Annual Planning Report

Draft recommendation

Each DNSP would publish on its website and make available to interested parties a Distribution Annual Planning Report (DAPR) by 31 December each year for the forward planning period beginning 1 January the following year.

The DAPR for a DNSP must be certified by its Chief Executive Officer (CEO) and a Director or Company Secretary that:

- the DAPR meets the DNSP's obligations under the Rules and any other applicable regulatory instruments; and
- the DAPR accurately represents the relevant policies of the DNSP.

Each DNSP would conduct a public forum within two months of publishing its DAPR.

Reasoning for draft recommendation

As required by the terms of reference for this Review, the draft recommendations require each DNSP to publish an annual planning report – the DAPR. Giving consideration to the timeframes required for DNSPs to prepare forecast information and consider outcomes from the transmission annual planning process, the draft recommendations require the DAPR to be published by 31 December each year, covering the forward planning period starting 1 January the following year.

Currently, in the jurisdictions that require DNSPs to publish an annual planning report, the reporting timeframes generally fall in the last quarter of the calendar year, although the exact timeframes vary. Most DNSPs were supportive of the DAPR being published in this same timeframe.

The proposed publication date for the DAPR of 31 December, would maximise the time available for DNSPs to produce and consider relevant forecast information, including the latest summer forecasts, while providing for information to be published in a timely manner. In addition, under the Rules, TNSP annual planning reports are required to be published by 30 June each year. A publication date after 30 June would provide for DNSPs to consider the relevant outcomes of TNSPs' reports. Providing time for the relevant information to be considered would increase the accuracy of the DAPRs and enhance the usefulness of the information published.

We seek comments on whether the publication date of 31 December is appropriate.

EnergyAustralia currently plans and operates both distribution and dual function transmission assets. Given its function, EnergyAustralia submitted that it should be allow to report on the planning of both its transmission and distribution assets in one report.[13]

We consider that it would be sensible for each network service provider to produce one comprehensive planning report covering all its assets. However given the specific differences between the content requirements and the publication timeframe, allowing EnergyAustralia to combine its transmission and distribution reports may affect the ability of market participants, and especially the national transmission planner, to take a NEM wide view of future transmission issues. We would welcome comments from stakeholders on whether there any objections to allowing EnergyAustralia to produce one comprehensive planning report.

DNSP public forum

To increase the transparency and accessibility of the information contained in the DAPR, the draft recommendations require DNSPs to conduct a public forum on their DAPR within two months of the report being published each year. The public forum would increase the ability of stakeholders to understand the information contained in the report through direct engagement with DNSPs. This requirement meets the principle of proportionality as there are likely to be significant benefits to be gained by both DNSPs and non-network proponents through direct discussion and engagement.

The draft recommendations also require the DAPR to be certified by the CEO and a Director or Company Secretary. Certification would ensure the report meets the necessary regulatory requirements and accurately represent the policies of the DNSPs. As the DAPR would set out forecasts, which would be based on

[13] EnergyAustralia, submission to the Workshop/Workshop Paper, p. 4.

assumptions, certification would not be a commitment to achieving the forecast values and activities. This would increase confidence in the content of the DAPR.[14]

Publication of reports on DNSP websites

The DAPR and other documents required under the RIT-D should be made public and published on each DNSP's website. It is considered important for DNSPs to retain responsibility of the documents they produce. Stakeholders would also have the opportunity to register with DNSPs as an interested party to be advised of any publications under the Demand Side Engagement Strategy. We do not consider that it would be necessary to have a single point where all the DNSPs' annual planning reports can be accessed. This draft recommendation is consistent with the principle of proportionality as it would minimise the costs of maintaining the publications.

2.5 Joint Planning Requirements

2.5.1 Joint planning between Transmission Network Service Providers and Distribution Network Service Providers

Draft recommendation

Each DNSP would be required to undertake joint planning with any TNSP, which operates a transmission network connected to the DNSP's distribution network.

The joint planning would require the TNSP and the DNSP to meet on a regular, and as required, basis to undertake annual planning of their transmission and distribution networks over the relevant forward planning period. The parties would be required to use best endeavours to work together to achieve efficient planning outcomes and investments.

The joint planning would identify any system limitations that would affect both the transmission and distribution networks or would require action by both the TNSP and DNSP to address a system limitation.

Reasoning for draft recommendation

The joint planning arrangements undertaken by TNSPs and DNSPs are an important consideration in the national framework, given the volume of potential projects that affect both transmission and distribution networks.[15]

Under the current Rules, TNSPs and DNSPs are required to undertake joint planning on an annual basis. The draft recommendations recognise that the current provisions

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[14] This view was supported by TEC in its submission to the Workshop/Workshop Paper, p. 5.

[15] For example, a projected limitation on the capacity of a major transmission/distribution connection point may be able to be addressed by either augmentation of the connection point by the TNSP or by augmentation to the distribution network by the DNSP to move the load to alternative connection points.

and processes adopted by TNSPs and DNSPs appear to be working effectively. As noted by Grid Australia:

> The experience of Grid Australia members is that the current provisions in the Rules around joint planning and investment are generally suitable.[16]

CitiPower and Powercor also noted:

> The Businesses support a continuation of the current arrangements whereby it is the obligation of the party with the nominated planning responsibility to identify the need for the augmentation, to carry out the necessary test with relevant input from other parties affected.[17]

The draft recommendations clarify the requirements for joint planning and provides that the parties should meet regularly to carry out joint planning. This will maintain the current practices for joint planning, which is consistent with the principles of transparency and proportionality.

SP Ausnet submitted that the national framework should state that, where parties cannot agree on a lead party, the DNSP should be responsible for any investments that would provide a service to meet a distribution need.[18] However a joint obligation to work together is preferred as each network service provider should retain control over the planning of the network which it operates.

Victorian Provisions

In Victoria, DNSPs are responsible for planning and directing the augmentation of transmission connection assets under their licence conditions.[19] This provision is unique to Victoria. In other jurisdictions this is a TNSP responsibility. Some Victorian DNSPs have raised issues relating to the complexity surrounding the classification of transmission connection augmentations. In light of the experiences of some Victorian DNSPs, SP Ausnet suggested that:

> …it is important that the Rules explicitly articulate the planning role and responsibilities for DNSPs. SP Ausnet firmly believes that it should be the DNSP which is responsible for conducting the Regulatory Test analysis and making investment decisions for its distribution network as it is ultimately responsible to its customers for its network service.[20]

The draft recommendations provide for the Victorian DNSPs to maintain their responsibility for planning transmission connections as the annual planning process includes the flexibility for specific jurisdiction requirements. We consider that the

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16 Grid Australia, submission to the Workshop/Workshop Paper, p. 2.

17 CitiPower and Powercor, submission to the Workshop/Workshop Paper, p.2.

18 SP Ausnet, submission to the Workshop/Workshop Paper, p. 3.

19 Clause 14 in the distribution licence of each Victorian DNSP.

20 SP Ausnet, submission to the Workshop/Workshop Paper, p. 3.

proposed recommendations provides clarity and places obligations on both parties to come together and work towards identifying the most economic option. However, we seek comments on whether specific additional provisions is needed and will also undertake further consultation with the Victorian parties to consider whether any appropriate amendments may be made to the proposed national framework.[21]

We seek comments on whether additional requirements should be provided to clarify the joint planning processes between TNSPs and DNSPs in Victoria.

2.5.2 Regulatory Investment Test for Investments identified through Joint Planning

Draft recommendation

Where the necessity for augmentation or a non-network alternative is identified by the process under the joint planning provisions NSPs:[22]

- would jointly determine plans that can be considered by relevant Registered Participants, AEMO and interested parties;
- would carry out the Regulatory Investment Test for Transmission (RIT-T) for the options identified;
- may agree on a lead party to be responsible for carrying out the RIT-T. In this case, the other parties would be deemed to have discharged their obligations to undertake the Regulatory Investment Test for the identified need for investment.

Reasoning for draft recommendation

The RIT-T should be applied to any investments identified through the joint planning process that affect both the transmission and distribution networks (a joint investment).[23] The application of one regulatory test would be consistent with the economic efficiency principle as it would ensure that the optimal overall solution would be identified. It would also be consistent with the transparency principle as it would provide clarity over the processes adopted and a more efficient assessment

[21] It is noted that, in their submissions to the Scoping and Issues Paper, CitiPower & Powercor and SP Ausnet noted that the Rules should be clarified such that they provide for all transmission charges to be passed through to network users via distribution tariffs. The DNSPs considered that the current clause 6.18.7 does not provide for the pass through of costs arising from transmission connection assets. However, as they submitted that DNSPs have adequate incentives to plan connections assets efficiently, all the costs from transmission connections should be able to be passed through to customers.

[22] It is noted that implementation of these provisions would require changes to the Rules. This may include changes to Rule 5.6.2, which were recently amended under the RIT-T Rule change. Additional information on this Rule change is available at www.aemc.gov.au.

[23] For the avoidance of doubt, dual function assets will be assessed under the RIT-D.

process overall. The approach of applying one assessment process is supported by stakeholders.[24]

Some DNSPs have submitted that, although they agree one regulatory investment test should be applied to joint investments, they consider the Regulatory Investment Test for Distribution (RIT-D) should apply as the RIT-T requires the consideration of market benefits.[25]

The draft recommendations provide that the RIT-T would apply to joint investments as the RIT-T requires that a broader range of market benefits must be assessed. This would ensure any applicable market benefits would be appropriately considered. The RIT-T would apply to any projects that need to be planned jointly, irrespective of the balance of investment between the two networks. As joint investments could require investments to the transmission network (as well as the distribution network), the consideration of potential market benefits would be a key factor in the assessment of investment alternatives. This would ensure that the most economic option to the identified need is selected. We also note that there is substantial commonality between the project assessment process under the two tests (see Chapter 4 for detailed discussion).

In undertaking joint planning, TNSPs and DNSPs would be required to consider whether any market benefits apply in regards to augmentations driven by distribution requirements as well as transmission requirements. Should no market benefits be identified, the RIT-T would provide for a least cost assessment to be completed. For these reasons, the draft recommendations provide that the RIT-T apply to joint investments, as it would provide for a comprehensive assessment of investment options, whilst maintaining flexibility.

We have proposed that the RIT-D should apply to an identified need where the most expensive investment option has a capital cost of $2 million or more (see Chapter 4 for further details). As a result, there will be a difference in the cost threshold applied to the two regulatory investment tests. To address this issue, we propose that as the RIT-T would apply to joint investments, joint investments should be subject to the RIT-T threshold, which is currently set at $5 million. For joint investments between $2 million and $5 million, the RIT-T would still need to be carried out, however, the projects would be exempt from the project specification and draft project assessment reporting requirements.

2.5.3 Joint planning between Distribution Network Service Providers

Draft recommendation

The Annual Planning Process would require DNSPs to meet regularly to undertake joint planning with other DNSPs, where there is a need to consider any

24 See, for example, submissions from VENCorp and Ergon Energy to the Scoping and Issues Paper.

25 See, for example, submission from Energy Australia to the Workshop/Workshop Paper.

augmentation or non-network alternative that affect more than one distribution network.

Reasoning for draft recommendation

In jurisdictions where there are multiple distribution networks and DNSPs, investments that affect more than one network would require DNSPs to jointly plan. Currently, there are no specific provisions in the Rules reflecting this work that is carried out by DNSPs. It is noted that the degree of interaction required between DNSPs and the complexity of issues may vary across jurisdictions. The draft recommendations clarify this to provide for greater transparency and consistency between jurisdictions.

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3 Reporting Requirements

This Chapter discusses the draft recommendations on the reporting requirements for the annual planning process. It describes each proposed section of the Distribution Annual Planning Report (DAPR) and sets outs the supporting reasoning for the proposed content.

To achieve an appropriate balance between the regulatory requirements on DNSPs and benefits to the broader market, the draft recommendations propose that the scope of the reporting requirements should only encompass a section of the planning activities undertaken. The reporting requirements should only require the publication of information that would provide benefits to the broader market. The level of detail required in the DAPR recognises the nature and importance of each asset and asset class, the volume of applicable projects, and the benefits of the information.

Summary of draft recommendations

7. The scope of the DAPR would relate to the power system and direct control services.

8. The DAPR would include forecasting information. This would include capacity and load forecasts at a system, sub transmission and zone substation level, and the identification of any overloaded primary distribution feeders.

9. The DAPR must inform on system limitations. System limitations should relate to any requirement for distribution investments, which would cover more than network constraints.

10. Information would be reported on system limitations including the location and timing, analysis of potential load transfer capability, impact on the transmission connection points, and potential solutions that may address each limitation. An explanation of the DNSP's planning methodology would also be reported on.

11. Information would be reported on investments that have been assessed under the RIT-D (or will be assessed) and projects with a capital cost of $2 million or greater that were urgent and unforseen investments or refurbishment or replacement projects.

12. Other reporting would be required on: a description of the network, outcomes from joint planning undertaken with TNSPs and other DNSPs, performance standards and compliance against those standards, and a summary of the DSNP's asset management methodology.

3.1 Purpose of Planning Reports

The purpose of the DAPR is to inform on the outcomes of DNSPs' planning processes under the national framework. The reports should provide an appropriate level of detail, and balance the potential benefits of providing the information with the potential costs of preparing the reports. They should provide sufficient information to allow non-network proponents to identify potential investment opportunities that could be exploited through further dialogue with the DNSPs.

Customers should be able to use the annual planning reports to optimise investments and promote efficient decision making. The reports should also assist interested parties to identify and assess the possibility of establishing new connections at the most efficient location and assess the potential impact for upstream augmentations.

Regulators could also use the DAPR to develop their information requirements and understand the activities undertaken by DNSPs. An annual reporting process would provide regulators with updated information on a more frequent basis compared to, for example, a five-yearly basis under the regulatory control period. This would improve the level of information available across the industry, help overcome any information-asymmetries, and assist the AER's five-year revenue determination processes.

3.2 Context of the Planning Report

The draft recommendations focus on the reporting of system limitations that have been identified on the distribution network, with a particular emphasis on sub transmission assets and zone substations. Other reporting on the planning methodology adopted and forecast information would support the analysis on system limitations, particularly considering the different planning and forecasting methodologies used by DNSPs across the NEM. The information published in the DAPRs is supported by the Demand Side Engagement Strategy where the information contained in a DAPR would promote further engagement between DNSPs and interested parties.

In developing the requirements for a national framework, consideration has been given to the current planning provisions in each jurisdiction. We consider that the proposed content for DAPR maintains the core of existing jurisdictional requirements and therefore would not lead to substantial increases in the regulatory costs on DNSPs. A comparison of the draft recommendations and the current jurisdictional reporting requirements is set out in Appendix F.

Planning Report Guidelines

In our Scoping and Issues Paper, comments were sought on whether the Rules should require the establishment of guidelines to set out the standard format and content of the annual planning report.[26] It is considered that outlining the reporting

[26] Scoping and Issues Paper, p. 33.

provisions in the Rules promotes certainty and stability of regulatory outcomes. In developing the draft recommendations, consideration of the ability to provide for differences in the jurisdictional requirements in a transparent manner was taken into account. For these reasons, it is considered that guidelines for the DAPR would not be required.

3.3 Scope of the Reporting Requirements

Draft recommendation

The scope of the DAPR would include system limitations and investments that:

- are for services that would be provided as direct control services;
- relate to the power system; and
- are sub transmission assets or zone substations or, on an exception basis, primary distribution feeders.

Reasoning for draft recommendation

The DAPR should provide sufficient information to allow non-network proponents to seek further information and develop alternatives to address potential system limitations. In addition, the DAPR should assist with identifying appropriate locations of spare transfer capability to assist potential connections to the network.

To meet these objectives in a manner that is proportionate, it is proposed that the scope of the annual reporting requirements include sub transmission assets, zone substations, and ,on an exception basis, primary distribution feeders. The performance of these assets is likely to have a material impact on the network. This scope also captures developments where potential non-network solutions are most likely to be feasible.

To provide clarity in the Rules as the scope of system limitations that would need to be included in the DAPR, it is proposed to define:

- a sub transmission asset as a “substation or switching station connected with primary voltages greater than 33kV and is not a transmission asset”; and
- a primary distribution feeder as a “distribution line 11kV or greater”.

We seek comments on the definition of sub transmission assets and primary distribution feeders as to whether the proposed definitions would capture all the sub transmission assets owned and operated by DNSPs and relevant primary distribution feeders.

Reporting would be limited to investments in the power system, to exclude expenditure on organisational support and other projects which are not directly relevant to the transfer capability of the network (e.g. IT system upgrades). However, given that distribution networks are becoming more “active networks” and the increasing importance of real time metering, the DAPR should inform on any significant investments in metering services. Further work is needed on correctly specifying this requirement in the Rules to achieve the appropriate balance.

We seek comments on how significant investments in smart metering should be captured by the annual reporting requirements and specified in the Rules.

3.4 Identifying System Limitations

The DAPR would identify system limitations for the defined asset classes outlined in the scope of reporting . The DAPR would recognise that problems (or system limitations) on the network may be caused by a number of factors and would identify these factors. The DAPR would also require forecasting information to be published.

3.4.1 Forecasting

Draft recommendation

The DAPR would include forecasts for the forward planning period, including at a minimum:

i. description of the forecasting methodology used; sources of input information; and the assumptions applied;

ii. forecasts for the network as a whole; major transmission and sub transmission connection points; zone substations; sub transmission assets; including:

   1. total capacity;
   2. firm delivery capacity (summer and winter);

iii. load forecasts for the network as a whole; major transmission and sub transmission connection points; zone substations; sub-transmission assets; including:

   1. peak load (summer and winter);
   2. power factor at time of peak load;
   3. load sharing/load transfer capabilities; and
   4. level of embedded generation;

iv. forecasts of future connection points and zone substations: including location; future loadings; and estimated timing (month, year) of the connections;

v. forecasts of reliability targets at a system level and by feeder categories; and

vi. forecasts of any factors that may have a major affect on the *distribution network* and *sub transmission network*, including factors affecting:

   1. fault levels;

2. voltage levels;
3. other system security requirements; and
4. ageing and potentially unreliable assets.

In addition, the DAPR should specifically include information on any primary distribution feeders that have exceeded in the current year, or was forecast to exceed within the next two years, 100 per cent of the normal cyclic rating (summer or winter) under normal operating conditions. The information to be provided would include:

i. the location of the primary distribution feeder;
ii. the extent of overload experienced in the current year;
iii. the forecast load in the next two years, and identifying the extent the forecast load would exceed the normal cyclic rating (summer or winter);
iv. any potential solutions being considered by the DNSP to address the overload; and
v. where an estimated reduction in forecast load would defer the overload for a period of 12 months, include:[27]
    1. the year and month in which a overload forecast to occur;
    2. the relevant connection points at which the estimated reduction in forecast load may occur; and
    3. the estimated reduction in forecast load in MW needed.

Reasoning for draft recommendation

Forecast information, including load forecasts, is a key input in identifying system limitations under the planning process. As the DAPR would be published each year, the latest forecast information being considered by DNSPs would be available to stakeholders, including the AER. Although DNSPs currently provide relevant information to the AER at least once every five years, by publishing updated information annually, the AER would have access to this information on a more regular basis. In the long term, this may reduce the time required by the AER and DNSPs in managing regulatory activities.

Information on any overloaded primary distribution feeders would also enhance the ability of users and non-network proponents to identify feasible opportunities for embedded generation and demand management. Under industry best practice, it is likely that DNSPs would regularly identify and plan for overloaded distribution feeders. The draft recommendations provide transparency on the work carried out by DSNPs, while enhancing the information available to the interested parties. This is consistent with the principles of transparency and proportionality.

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[27] This clause is consistent with the clause introduced under the National Electricity Amendment (Demand Management) Rule 2009 No. 11. Additional information on this Rule change may be found at www.aemc.gov.au.

The draft recommendations require a summary of the forecasting methodology adopted by DNSPs, including an explanation of any assumptions applied. This would provide transparency to the forecasting process to ensure that the information provided would be useful and may be appropriately considered and compared. This is especially important given the different forecasting methodologies used by DNSPs.

Forecasts of distribution loss factors

In the Scoping and Issues Paper, comments were sought on whether the DAPR should include forecasts of distribution loss factors (DLFs). It is noted that forecasting DLFs may be a complicated and costly process. Given that any forecasts of DLFs would be highly sensitive to changes in network conditions, no evidence has been received to support that forecasts of DLFs would provide any measurable benefit.[28]

For these reasons, the draft recommendations do not include the requirement to produce forecast DLFs.

3.4.2 Definition of system limitations

Draft recommendation

System limitations for sub transmission assets and zone substations would be any situation where there is a limitation caused by one or more of the following factors:

- forecast load exceeding system capability;
- the requirement for asset replacement or refurbishment;
- the requirement for system security or reliability improvement;
- design fault levels being exceeded;
- the requirement for voltage regulation; and
- the requirement to meet System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) or any other regulatory obligations.

Reasoning for draft recommendation

The concept of system limitations is intended to reflect a problem that has been identified on the network or a “constraint” on the network.[29] System limitations are a key consideration in the planning process as they identify the potential problems on the network that may require augmentation or a non-network solution.

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[28] See, for example, submission from Energex to the Scoping and Issues Paper, p.6.

[29] It is noted that Scoping and Issues Paper had sought comments on the appropriate definition of a “network constraint”.

To ensure that the information provided is comprehensive and consistent across jurisdictions, the draft recommendations define a system limitation as a potential problem on the network that may be due to a defined list of causes. DNSPs would be required to provide an explanation of the cause of a potential problem in the DAPR.

The potential causes of a system limitation include the requirements for the DNSPs to meet the required SAIDI and SAIFI and other jurisdictional standards. This has been included in the draft recommendations as the requirement to meet these standards may result in augmentations on the network. In addition, non-network solutions could potentially alleviate such a system limitation.

3.4.3 Reporting on system limitations

Draft recommendation

For any system limitations identified, the following would be required to be reported in the DAPR:

- the location and timing (month, year) of the system limitation;
- analysis of any potential load transfer capability between supply points that may decrease the impact of the system limitation or defer the requirement for investment;
- impact of the system limitation, if any, on the capacity at the transmission connection points;
- discussion of the potential solutions that may address the system limitation in the forward planning period, if a solution is required; and
- where an estimated reduction in forecast load would defer a forecast system limitation for a period of 12 months: including the timing (month, year) the system limitation would occur; the relevant connection points at which the estimated reduction may occur; and the estimated reduction in load needed in MW.[30]

Reasoning for draft recommendation

The objectives of the DAPR include transparency and providing information to allow interested parties to identify potential areas for non-network alternatives and other investments (e.g., embedded generation). Providing information on the system limitations identified would form a key component to meeting these objectives. Including information on the location of the system limitation and the cause of the system limitation would enable network users to make efficient decisions and non-network users to propose feasible credible alternatives. Information on options be considered by DNSPs to address a system limitation, is also beneficial to stakeholders.

[30] This requirement is consistent with the amendment made to the Rules under National Electricity Amendment (Demand Management) Rule 2009 No. 11, which came into effect on 1 July 2009. Additional information on this Rule change may be found at www.aemc.gov.au.

Information on transfer capability would also assist potential investors to determine their ability to connect to the distribution network and to understand the feasibility of non-network solutions. However, DNSPs did not agree on whether this information should be included. While some DNSPs supported including transfer capability information, others did not. Ergon Energy noted:

> Ergon Energy does not support the inclusion of [information on transfer capability of the shared network] as the impacts are not static and subject to change with changes to load flow over the network. Ergon Energy considers that this information is more appropriately and accurately, provided upon application to the DNSP.[31]

Information in the DAPR, including information on transfer capabilities, would be based on assumptions and forecast information. Due to the nature of such information, users of the report should be aware that the information would be subject to change. Information provided would be intended to assist non-network proponents as a basis to consider and assess potential investments and to promote further discussions and communications with DNSPs.

It is noted that some jurisdictions require DNSPs to produce "regional development plans". The draft recommendations do not specifically require regional development plans to be produced. However, DNSPs would be required to identify the location of any system limitations and thereby enable users of the report to identify where system limitations may occur in any given region.

We seek comments on whether the national framework should include a requirement for DNSPs to develop regional development plans.

The draft recommendations would require DNSPs to include a summary of their planning methodology in their DAPR. This would provide transparency to and clarify the processes adopted, particularly given each DNSP may use a different planning and forecasting methodology. The summary would assist users of the report, including regulatory bodies, to better understand the information provided in the DAPR. The planning and reporting process in the draft recommendations allow DNSPs to utilise their own planning methodologies to forecast and provide appropriate information, so long as their assumptions are clearly set out.

3.5 Reporting on Network Investments

Draft recommendation

Three categories of reporting would be required for network investments. These categories are:

1. Investments assessed or in the process of being assessed under the RIT-D – summary of projects;

[31] Ergon Energy, submission to the Scoping and Issues Paper, p. 8.

2. Investments that will need to undergo the RIT-D assessment – summary of project details where available; and

3. Other committed projects where the capital cost of the project was $2 million or more that were urgent and unforseen or any refurbishment or replacement projects.

Reasoning for draft recommendation

The key outcome from the planning process would be the identification of the investments required to address specific system limitations. The RIT-D process outlines the project specification and assessment requirements for each investment to which the RIT-D applies (refer to Chapter 4, which discusses the RIT-D process in detail). Although the RIT-D identifies the specific information that DNSPs would publish under the project assessment process, providing a summary in the DAPR would allow the outcomes of the planning process to be captured in an accessible format.

Users of the DAPR could use this information to improve their understanding of the planning and investment process. The summary should provide general information on the investments that have been considered. This would be consistent with the proportionality principle as it would ensure that there would not be a material impact on DNSPs in providing this information.

Under the RIT-D, we have proposed that "urgent and unforseen" investments be exempt from the RIT-D process. DNSPs would be required to report on any committed investments that were urgent and unforseen, which have a capital cost of $2 million or more in their DAPR. Urgent and unforseen investments, by their nature, could have a material impact on the distribution network.

In addition, reporting should also include refurbishment or replacement projects, where the capital cost of the project was $2 million or more. As many replacement projects may have an impact on the augmentation activities undertaken by DNSPs, including replacement projects in the reporting process would increase the transparency of the planning process by ensuring a specified level of information is available for investments that fall outside the RIT-D process.

3.6 Other Reporting

To support the key information on system limitations, the draft recommendations require a range of other information to be included in the DAPR. It is noted this additional information would provide an important context to DNSPs' planning activities, system limitations, and investments. To this end, this supporting information would be at a higher level than the more detailed information on system limitations. This additional information takes into consideration existing jurisdictional requirements to ensure that the robustness and accountability of the distribution planning requirements would not deteriorate.

3.6.1 Description of the network

Draft recommendation

The DAPR would require an explanation of the general characteristics of the network.

Reasoning for draft recommendation

The distribution networks across the NEM have different characteristics due to geographical requirements and legacy systems that have affected the way that networks have been planned and augmented. The draft recommendations require some general information on the description of the network and the operating environment. Such standard descriptions should have limited cost and operational impacts on DNSPs, while the potential benefits in providing clarity on the network, would be valuable to users of the DAPR. In addition, the requirements would also allow each DNSP to appropriately capture and describe any particular characteristics that may be unique to its network.

3.6.2 Joint planning

Draft recommendation

The DAPR would include a summary of DNSPs' joint planning activities with TNSPs and other DNSPs, and identify where additional information on the joint planning process may be obtained.

Reasoning for draft recommendation

As discussed in Chapter 2, TNSPs and DNSPs would be undertake joint planning to identify any joint investment requirements. The draft recommendations require that a summary of the activities undertaken by DNSPs under the joint planning process be included in the DAPR. This would include information on the jointly planned investments (which would include any joint investments that were exempt from the RIT-T). This would provide transparency to all the planning processes undertaken by a DNSP and provide a discipline for the parties to meet on a regular basis. For these reasons, a similar level of reporting for joint planning activities between DNSPs has also been included.

3.6.3 Performance standards and compliance

Draft recommendation

A high level of information on reliability and quality of supply standards would be included in the DAPR. This would include qualitative assessments of the performance of the network over the previous year and any areas where the relevant standards were not met.

Reasoning for draft recommendation

The reliability and quality of supply standards impact the planning activities of DNSPs and the need for investment. Therefore, providing a summary of these provisions would ensure clarity and enhance the usefulness of the information reported in the DAPR. As the standards vary in each jurisdiction, providing this information would assist non-network proponents that operate in more than one jurisdiction and increase the transparency to regulators.

The Scoping and Issues Paper raised the issue of whether historical data should be included on network performance.[32] Some stakeholders noted that planning should focus on current and future network developments and, for this reason, be forward looking and not include historical information.[33] Energy Response on the other hand, believed that information should be included on historical performance, including how DNSPs have performed compared to previous forecasts:

> [The Distribution Annual Planning Report] should follow up on the constraints and other problems raised in previous planning reports, showing what actins have been taken, and how reality compares to the previous predictions.[34]

In response to these considerations, the draft recommendations require DNSPs to provide a qualitative assessment of the network performance over the preceding year and how the DNSPs have complied with the applicable standards. The requirement to include information on performance is consistent with current jurisdictional provisions. As the purpose of the planning report is to inform on the planning process and identify future system limitations, providing this qualitative assessment of the network's performance would compliment the other information in the DAPR. Including these provisions would provide for a robust planning framework, while allowing each DNSP to report on issues that are relevant to their jurisdiction.

3.6.4 Asset management

Draft recommendation

A summary of the business' asset management methodology should be included in the DAPR.

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[32] Scoping and Issues Paper, p. 16.

[33] For example, Jemena noted in its submission to the Scoping and Issues Paper, p. 3, "…the annual planning report should be focused on current and future network development. It should be a forward looking plan which provides information to both inform market participants of the planned projects and allow non-network proponents to identify opportunities for alternative solutions. There is no pressing reason for the [DAPR] to include historical information"

[34] Energy Response, submission to the Scoping and Issues Paper, p. 2.

Reasoning for draft recommendation

Asset management forms an important component in the overall planning process to ensure the efficient management and development of the distribution network. Asset management ensures the efficient provision of distribution services and provides the foundation for achieving a DNSP's company goals, by maximising the asset value through the optimisation of asset performance over the total asset lifecycle.[35] For these reasons, asset management has a direct influence on network planning.

To provide transparency and clarity to the overall planning process, the draft recommendations require the DAPR to include a high level summary of the asset management methodology adopted by the DNSPs. This draft recommendation gives consideration to the importance of asset management to planning activities, balanced with the cost of producing information on asset management. By providing a summary of the methodologies undertaken, the cost impact on DNSPs should be limited while providing clarity on the overall processes adopted.

Chapter 6 discusses the issues arising from the deficiency in a standardised approach to asset management across the NEM and suggests a number of areas for further work.

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35 This gives consideration to the purpose of asset management as discussed in *Electricity Distribution Business Asset Management Plans and Consumer Engagement: Best Practice Recommendations*, prepared be Parsons Brinckerhoff Associates for the Commerce Commission NZ, April 2005, pp. 10-11.

4 Regulatory Investment Test for Distribution

This Chapter sets out the Commission's draft recommendations for a new project assessment and consultation process for distribution investments (called the Regulatory Investment Test for Distribution (RIT-D)) to replace the current Regulatory Test. A diagram outlining the proposed design of the RIT-D can be found at Appendix D.

The Chapter describes the scope of investments which would be subject to the RIT-D, the assessment framework, and the required consultation stages. In considering the appropriate design for the RIT-D, we have used the design of the RIT-T as its basis and have recognised the nature and volume of investments undertaken at the distribution level. The Rules governing the RIT-D would be supported by the AER developing the RIT-D test and accompanying application guidelines.

Summary of draft recommendations

13. The purpose of the RIT-D would be to identify the preferred option for network investment which maximises the present value of net economic benefits. Where a proposed investment is required to meet deterministic reliability standards, the preferred option may have a negative net present value.

14. The RIT-D would be undertaken by DNSPs when a distribution system limitation exists and the most expensive option which is technically and economically feasible is expected to cost $2 million or more.

15. The RIT-D would not apply to urgent and unforseen investments, negotiated services, replacements, connection services, or where the proposed investment has been identified through joint planning processes between DNSPs and TNSPs.

16. The RIT-D would provide for a flexible assessment process, allowing for DNSPs' reporting and consultation requirements to be tailored to the characteristics of each proposed investment.

17. The RIT-D would involve:

- An initial screening test, the Specification Threshold Test (STT), to determine whether additional consultation and reporting would be required before the project assessment process;
- A project specification stage, where DNSPs would be required to consult to request alternative proposals to meet the identified need;
- An opportunity for DNSPs to consult under an accelerated consultation period on their project specification reports, if DNSPs have undertaken prior engagement with non-network proponents; and
- Consideration of applicable market benefits and costs for each credible option, to determine the preferred option. DNSPs would be required to quantify all applicable costs, but would have the discretion to quantify any applicable market benefits.

4.1 Purpose of the RIT-D

The MCE terms of reference require DNSPs to undertake a case by case economic project assessment process, to be triggered by defined thresholds. The MCE has requested that the project assessment process provide for appropriate information transparency regarding the analysis and decisions made by DNSPs to ensure compliance and accountability.

The RIT-D would provide a mechanism for DNSPs to assess and consult on investment options to meet an identified need to determine the most economic option. The potential benefits associated with the RIT-D relate mainly to improved efficiency and transparency in the development of distribution networks and would be captured mainly by consumers, non-network proponents and the AER. The potential benefits include:

- increased efficiency in the development of distribution networks through selecting the preferred investment option from a NEM wide perspective, rather than from DNSPs' commercial interests. This would result in more efficient (and potentially lower) network charges and improved reliability of supply for end users;

- the provision of formal opportunities for non-network proponents to raise credible alternatives and the neutral assessment of all credible options, thereby providing a safeguard against inefficient investments; and

- improved transparency, including more accessible and comprehensive reporting regarding the decision making process of DNSPs when considering investments. This would assist the AER's assessment of DNSPs' regulatory proposals.

The proposed RIT-D seeks to ensure that the process is fit for purpose and the costs of it are proportionate to its potential benefits. This is achieved by exempting defined investments from the RIT-D and tailoring DNSPs' reporting and consultation requirements to the characteristics of each identified need. The RIT-D also seeks to ensure that DNSPs develop their networks efficiently and in a technology neutral manner, by specifying the decision making criteria DNSPs must use when assessing different investment options and requiring them to report and publicly consult on their decision making processes.

4.2 Amalgamation of reliability and market benefits limbs

Draft recommendation

The RIT-D would comprise a single project assessment process under a cost-benefit framework. Therefore, the reliability and market benefits limbs of the current Regulatory Test would be amalgamated under the RIT-D.

The purpose of the RIT-D would be to identify the distribution investment option which maximises the present value of net economic benefits, subject to meeting deterministic reliability standards.

DNSPs would be required to consider the potential for market benefits when undertaking the project assessment process. DNSPs would be required to quantify all applicable costs for each credible option, but would be provided with the option to quantify any applicable market benefits, where they consider it appropriate to do so.

Where DNSPs do not quantify market benefits, the preferred solution would be the investment option which minimises net economic costs. However, a negative net present value would only be permitted where the purpose of the proposed investment is a reliability corrective action.

Where deterministic reliability standards exist, only incremental reliability benefits delivered in addition to the level of reliability required by the standard should be quantified.

Reasoning for draft recommendation

Under the proposed framework, all proposed investments which are subject to the RIT-D would be assessed under a cost benefit framework. There are significant advantages to having a single cost benefit project assessment process that can be applied consistently across all prospective projects, irrespective of the primary purpose. A single process allows all projects to be assessed against local reliability standards, as well as against their ability to maximise market benefits to the broader market. This would ensure that DNSPs adopt the most efficient option rather than merely the least cost option. A single economic project assessment process is also consistent with the project assessment process under the RIT-T. This draft recommendation supports the principle of economic efficiency and achieves consistency with the transmission arrangements.

Assessment of Market Benefits

Submissions to the Scoping and Issues Paper from a number of DNSPs highlighted the need for DNSPs to have flexibility in the consideration of market benefits, due to the limited market benefits available under distribution investments.[36] Some DNSPs also suggested that the consideration of market benefits should be excluded from the RIT-D completely, as market benefits are rarely a driver for distribution investments.[37]

By contrast, submissions from the Alternative Technology Association and the Consumer Utilities Advocacy Centre (CUAC) considered that a full cost benefit approach was necessary, as “an approach based purely on cost minimisation or maximising net benefits is unlikely to deliver the NEL objective”.[38]

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[36] For example see: Jemena, Submission to the Scoping and Issues Paper, pp. 3-4.

[37] For example see: Integral Energy, Submission to the Scoping and Issues Paper, p. 15; ENERGEX, Submission to the Scoping and Issues Paper, p. 12.

[38] CUAC, Submission to the Scoping and Issues Paper, p. 8; Alternative Technology Association, Submission to the Scoping and Issues Paper, p. 6.

Three possible approaches to amalgamating the current limbs of the Regulatory Test were considered:

- a full cost benefit approach, where DNSPs would be required to consider and quantify all applicable market benefits and costs;

- a material cost benefit approach, where DNSPs would be required to consider all applicable market benefits and costs, but would only be required to quantify material market benefits and costs (this is the approach that has been adopted under the RIT-T); and

- a more limited cost benefit approach, where DNSPs would be required to consider all applicable market benefits and costs, but would only be required to quantify all applicable costs. Under this approach, DNSPs are provided with the option of quantifying any applicable market benefits.

Of these three possible approaches, we recommend a more limited cost benefit approach be applied under the RIT-D , where DNSPs are provided with the option to quantify market benefits. This approach is more suited to the characteristics of most distribution investments, as distribution investments typically have more limited market benefits than transmission investments. Also, this approach is an improvement on the current arrangements where DNSPs are prevented from including market benefits into their project assessment analysis.

We also understand that the values of market benefits which can be achieved through distribution investments, are far smaller and less widespread than those possible in transmission. In light of these characteristics of distribution investments, a full cost benefit approach and a material cost benefit approach have the potential to impose a significant regulatory burden on DNSPs with minimal potential benefits.

Where DNSPs do not quantify market benefits, the RIT-D would effectively become a “least cost” test analogous to the test applied under the reliability limb of the current Regulatory Test. The preferred solution would be the option which minimises net economic costs. However, a negative present value would only be permitted where the proposed investment is required to address a reliability corrective action.

This design ensures that the project assessment process is fit for purpose for each proposed investment and the regulatory burden on DNSPs is proportionate to the potential benefits of the assessment process. The danger of DNSPs cherry picking only those market benefits that validate their preferred investments, should be prevented by requiring DNSPs to transparently state their reasons in their project assessment reports for their preferred option and by the ability for interested parties to raise disputes with the AER.

DNSPs would also be required to take into account any submissions they receive on their draft project assessment report before finalising their preferred option in their final project assessment report. The public consultation process would provide the opportunity for interested parties to put forward any applicable market benefits which, if quantified, have the potential to alter the DNSPs’ preferred solution.

4.3 Scope of investments subject to the RIT-D

Draft recommendation

The cost threshold for proposed investments subject to the RIT-D would be set at $2 million and be applied to the estimated capital cost of the most expensive option that is technically and economically feasible. [39]

Reasoning for draft recommendation

There should be a dollar threshold below which the RIT-D is not undertaken. This is a feature of the current Regulatory Test and would ensure that the administrative burden of the RIT-D remains manageable and achieves the principle of proportionality for the national framework.

Currently all augmentations to a distribution network, which are estimated to cost more than $1 million, are subject to the Regulatory Test under the Rules.[40] It is recognised that the threshold for the Regulatory Test was established in 2001 and that there have been real increases in the input costs of distribution assets since this time. Therefore, maintaining the current cost threshold of $1 million under the RIT-D has the potential to impose a disproportionate regulatory burden on DNSPs, by subjecting a volume of small scale projects to the project assessment process, which were previously not intended to be captured.

Submissions from Network Service Providers (NSPs) generally considered that the threshold for the RIT-D should not be set lower than $5 million.[41] In its submission, Grid Australia noted that a $5 million threshold would "subject a reasonable number of DNSP projects to public consultation, and would also align with the threshold for application of the RIT-T".[42]

SP AusNet and Integral Energy considered that a full consultation process under the RIT-D should be limited to major investments. SP AusNet considered that the threshold for full consultation should be set at $10 million, while Integral Energy suggested it be set at $20 million.[43]

By contrast, submissions from non-network proponents considered that the threshold for the RIT-D should be set far lower. Energy Response considered that the threshold for the project assessment process should be set at $500,000 and the

[39] As only investments required to "augment" a distribution network would be subject to the RIT-D, investments such as communications and IT systems, would not be subject to the RIT-D.

[40] See clause 5.6.2(g) of the Rules.

[41] See submissions on the Stakeholder Workshop Paper from: Grid Australia, p. 3; SP AusNet, p. 5; Integral Energy, p. 3. See submissions on the Scoping and Issues Paper from: Jemena, p. 6; United Energy Distribution, p. 5 ; ENERGEX, pp. 8-9.

[42] Grid Australia, Submission to the Stakeholder Workshop Paper, p. 5.

[43] SP AustNet, Submission to the Stakeholder Workshop Paper, p. 5; Integral Energy, Submission to the Stakeholder Workshop Paper, p. 3.

threshold for a request for proposal process should be set at $1 million.[44] Energy Response noted that the thresholds for the RIT-D should be set low as:

> Some relatively small projects are particularly suited for non-network solutions. For example, some distribution augmentations in rural areas, where peak growth rates may be relatively low, can be deferred by many years through the use of DSR or embedded generation.[45]

The Alternative Energy Association and CUAC suggested the threshold should be set at $200,000, with CUAC also proposing that the threshold could be adaptable depending on the relative customer impact of the proposed investment.[46]

Applying a defined cost threshold to determine the scope of the RIT-D has the potential of being relatively arbitrary and simplistic. In some instances, relatively low cost investments can have far reaching market impacts and conversely, some high cost investments may be fairly routine projects with only a limited impact on the quality of service of end users.

For these reasons, it is recommended that an initial screening test, the STT, be applied to all investments which are subject to the RIT-D. The STT would work in conjunction with the cost threshold for the RIT-D to determine the scope of projects which are subject to the RIT-D and the appropriate process DNSPs must apply for each investment. Investments which do not meet the requirements of the STT would be subject to a fast tracked RIT-D process with more limited reporting and consultation. As a result, the relative significance of the cost threshold would be reduced under the RIT-D in comparison to the cost thresholds which apply under the current Regulatory Test and the RIT-T, where there is no initial screening test. (See Section 4.5, which discusses the STT in detail).

RIT-D cost threshold

We recommend the cost threshold for the RIT-D be set at $2 million. It is considered that a threshold of $2 million would provide an appropriate balance between the regulatory burden placed on DNSPs to ensure transparency regarding DNSPs' decision making, and ensuring distribution investments proceed in a timely manner.

We have recommended that a lower threshold apply to the RIT-D than the RIT-T, as distribution investments on average have a lower capital cost than transmission investments. It would not be appropriate to align the threshold for the RIT-D with the $5 million threshold adopted for the RIT-T, as this would exempt a sizable proportion of distribution augmentations from the project assessment process.

Further, although the threshold for the RIT-T would be higher than that proposed for the RIT-D, investments which are subject to the RIT-T are required to undergo

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[44] Energy Response, Submission to the Scoping and Issues Paper, p. 3.

[45] Ibid.

[46] Alternative Energy Association, Submission to the Scoping and Issues Paper, p. 5; CUAC, Submission to the Scoping and Issues Paper, p. 5

more rigorous reporting, consultation and assessment requirements. By contrast, DNSPs would have greater flexibility and discretion under the RIT-D, as the processes (e.g. STT) they would be required to undertake would be more tailored to the characteristics of each identified need.[47]

We also recognise that there is greater potential for small scale non-network solutions to meet an identified need. As a result, the RIT-D should have a threshold which is low enough to subject such investments to public consultation, but which does not impose a disproportionate regulatory burden on DNSPs. A threshold of $2 million provides an appropriate balance between these competing objectives. Also under the STT, only investments which have potential for non-network solutions or an adverse impact on the quality of service of end users, would be subject to additional reporting and consultation under the project specification stage. We note that non-network proponents would be still be able to investigate and propose smaller scale projects through the Demand Side Engagement Strategy.

It is appropriate to apply the threshold to the most expensive option which is technically and economically feasible, rather than the preferred solution. DNSPs should be encouraged to undertake STTs earlier in the planning process; linking the threshold to DNSPs' preferred solution may unnecessarily delay the assessment process and may mean DNSPs are less receptive to alternative options.

4.3.1 AER review of cost thresholds

Draft recommendation

The AER would review the cost thresholds for the RIT-D every three years. This review would be done in conjunction with the AER's review of the RIT-T cost thresholds.

Any cost threshold which is used in the requirements for the DAPR (for example, the $2 million threshold for replacement expenditure and urgent and unforeseen investments) would also be subject to this review.

Reasoning for draft recommendation

We recommend that the cost thresholds for the RIT-D be subject to a periodic review by the AER every three years, rather than automatic annual indexation.

A review process is more appropriate than automatic indexation as it would provide for a more thorough analysis of changes in input costs and would allow market consultation to be considered in the determination of the appropriate values.

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[47] For example, as the RIT-T does not have an initial screening test, all transmission investments which are subject to the RIT-T are subject to an additional stage of reporting and consultation under the project specification stage. In contrast, under the RIT-D, only investments which meet the requirements of the STT would be subject to the project specification stage. TNSPs are also required to quantify all material market benefits under the RIT-T, while under the RIT-D it is proposed that DNSPs be provided with the option to quantify any applicable market benefits.

Further, automatic indexation may have limited value as the input costs for distribution investments are unlikely to vary by a significant amount year to year. [48]

The AER's review would involve a review of changes in the input costs of distribution investments rather than a review of the material value of the cost thresholds. The AER has also been tasked with reviewing the cost thresholds for the RIT-T. It is proposed that the AER be required to undertake its review of the cost thresholds for the RIT-D in conjunction with its review of the RIT-T cost thresholds. In accordance with the principles for the national framework, this would provide for greater consistency between the RIT-T and RIT-D thresholds and improved efficiency in the AER's review processes. Therefore, we have proposed that the first RIT-D cost threshold review should commence by 31 July 2012, in order to align it with the AER's review of the RIT-T cost thresholds.

4.4 Exemptions from the RIT-D

Draft recommendation

The following distribution investments would be exempt from the RIT-D:

- investments which are required to augment a distribution network, where the estimated capital cost of the most expensive option which is technically and economically feasible is less than $2 million;
- urgent and unforseen investments;
- investments designed to ensure than a transmission network meets required security and reliability standards;
- investments where the need for the proposed investment has been identified through a joint planning process between a DNSP and TNSP;
- investments which would be provided as a negotiated distribution service, alternative control service or an unclassified service;
- connection assets, which would not be part of the DNSP's shared network;
- investments related to the refurbishment or replacements of assets which are not intended to augment the network; and

[48] The Commission considered a Rule change proposal in 2008 from Grid Australia titled 'Regulatory Test Thresholds and Information Disclosure on Network Replacements', which proposed the automatic indexation of the Regulatory Test cost thresholds for transmission investments. During its assessment of this Rule change proposal, the Commission found that the input costs for transmission investments had not varied considerably on an annual basis between 2002 and 2008. Due to the similarity of inputs used in distribution and transmission investments, it is considered that the input costs for distribution investments would also be unlikely to vary by a significant amount on an annual basis.

- refurbishment or replacement expenditure which also results in an augmentation to the network, where the estimated capital cost for the augmentation component is less than $2 million.

The reasoning for such exclusions is set out below. We are also considering the option of exempting primary distribution feeders from the RIT-D. This issue is discussed in further detail in section 4.4.3.

4.4.1 Exemptions from the RIT-D - Replacement investments

Draft recommendation

Investments related to the refurbishment or replacement of existing distribution assets, which are not intended to augment the distribution network, would be exempt from the RIT-D. However, where the refurbishment or replacement expenditure also results in an augmentation and that the augmentation component has an estimated capital cost of $2 million or more, these investments would be subject to the RIT-D.

DNSPs would be required to report on the details of any investments related to the refurbishment or replacement of sub-transmission and zone substation assets in their DAPR, where the estimated capital cost of such investments is $2 million or more.

Reasoning for draft recommendation

Submissions from NSPs strongly supported the exclusion of replacements from the RIT-D and stated that the RIT-D should only apply to augmentations to a distribution network.[49] Submissions from DNSPs generally considered that the inclusion of replacements in the scope of the RIT-D would provide minimal benefit as there is limited scope for alternatives to defer or remove the need for replacement projects.[50]

Workshop attendees at the stakeholder workshops noted that the inclusion of replacements would significantly increase the administrative burden on DNSPs due to the number of replacements they currently undertake. Further, as noted by Powercor & Citipower, "asset replacement programmes are rigorously tested during each price review and under the current incentive framework distributors have strong incentives to undertake efficient and prudent expenditure".[51]

[49] See submissions on the Scoping and Issues Paper: from: United Energy Distribution, p. 5; Ergon Energy, p. 10; Powercor & Citipower, p. 4. See submissions on the Stakeholder Workshop Paper from: EnergyAustralia, p. 7; Integral Energy, p. 3; Powercor & Citipower, p. 4; SP AusNet, p. 4; Grid Australia, p. 3.

[50] See submissions on the Scoping and Issues Paper: from: United Energy Distribution, p. 5; Ergon Energy, p. 10; Powercor & Citipower, p. 4. See submissions on the Stakeholder Workshop Paper from: EnergyAustralia, p. 7; Integral Energy, p. 3; Powercor & Citipower, p. 4; SP AusNet, p. 4.

[51] Powercor & Citipower, Submission to the Stakeholder Workshop Paper, p. 4.

However, submissions from EnergyAustralia and SP AusNet on the Stakeholder Workshop Paper supported the inclusion of replacements in the RIT-D, where there is an augmentation component to the replacement investment which meets the RIT-D cost threshold.[52]

Providing greater rigour to the assessment of replacement investments is likely to improve the optimisation of the timing of such investments. It is also noted that the catastrophic failure of aging distribution assets has the potential to lead to widespread outages, particularly in urban areas. However, including like for like replacements within the scope of the RIT-D may impose a disproportionate regulatory burden on DNSPs, due to the large volume of replacements undertaken by DNSPs and the limited alternatives for replacement investments. To require DNSPs to apply the RIT-D in these circumstances would represent an unnecessary regulatory burden, particularly as public consultation and reporting on the assessment of replacement investments, is unlikely to yield alternative solutions which may be more efficient. This proposed exemption supports the principles of proportionality and consistency with the arrangements for transmission.

Replacement expenditure by DNSPs would still be subject to the financial incentives promoting efficient behaviour under the regulatory framework for distribution services in Chapter 6 of the Rules. Further, where a replacement investment has an augmentation component with an estimated capital cost equal to or greater than $2 million, the replacement investment would be subject to the RIT-D and the project assessment process. This is consistent with the scope of transmission investments which are subject to the RIT-T. A large proportion of replacement investments undertaken by DNSPs have some component of augmentation. As such, this provision to exempt replacement investments, would provide an appropriate balance between the regulatory burden imposed on DNSPs and the need for greater rigour regarding the assessment of replacements.

DNSPs would be required to report in their DAPR on any like for like replacements and refurbishment of sub transmission and zone substation assets which are exempt from the RIT-D and have an estimated capital cost is $2 million or more. This would ensure that appropriate information transparency on DNSPs' decisions regarding significant like for like replacements and refurbishments is provided.

4.4.2 Exemptions from the RIT-D - Urgent and unforseen investments

Draft recommendation

"Urgent and unforseen investments" would be exempt from RIT-D. An investment would be defined as "urgent and unforseen" if:

- the proposed investment is required to be operational within 6 months of the DNSP identifying the identified need; and

[52] See submissions on the Stakeholder Workshop Paper from: SP AusNet, p. 4; EnergyAustralia, p. 7.

- the event or circumstances causing the identified need was not reasonably foreseeable by, and was beyond the reasonable control of, the DNSP; and
- a failure to address the identified need is likely to materially adversely affect the reliability and secure operating state of the distribution network.

DNSPs would be required to report on the details of any urgent and unforseen investments in their DAPR which have a capital cost of $2 million or more.

Reasoning for draft recommendation

An exemption from the RIT-D should be provided for distribution investments which are "urgent and unforseen", to ensure that the new regulatory regime does not reduce or adversely impact the ability for necessary but unanticipated investments to be made by DNSPs. A similar exemption is in place for transmission investments under the RIT-T. It should be noted that this exemption is not intended to include large customer connections which may be required at short notice, as negotiated services and customer connections which are not part of the DNSP's shared network, would be exempt from the RIT-D.

Submissions on the Scoping and Issues Paper generally supported an exemption from the RIT-D for urgent and unforseen investments.[53] However, submissions from non-network proponents such as the Alternative Energy Association and CUAC suggested that defining "urgent and unforseen" was problematic and that such an exemption may risk exacerbating any inherent conflicts of interests that DNSPs may have in assessing non-network alternatives.[54] The AER also indicated in its submission that this exemption should preclude errors of planning or demand forecasting.[55]

The intention of this exemption is that it would be used rarely by DNSPs and should not be used in place of accurate and timely planning practices. While there is potential for this exemption to be exploited by DNSPs, this risk is relatively low. Misuse of this exclusion would represent a failure to comply with the Rules, which would be subject to the AER's enforcement measures. In the absence of extenuating circumstances (such as extreme weather), the exemption for urgent or unforeseen investments represents an admission of a planning failure by the relevant DNSP, and would carry a reputational cost.

Also, as discussed further in Chapter 3, DNSPs would be required to report on the details of any urgent and unforseen investments in their DAPR where the capital cost of these investments was $2 million or more. It is considered that this provision would provide appropriate transparency regarding DNSPs' use of this exemption.

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[53] See submissions on the Scoping and Issues Paper from: Ergon Energy, p. 14; United Energy Distribution, p. 9; ENERGEX, p. 15; ENA, p. 15; Country Energy, p. 12.

[54] See submissions on the Scoping and Issues Paper from: CUAC, p. 11; Alternative Energy Association, p. 9.

[55] AER, Submission on Scoping and Issues Paper, p. 15.

4.4.3 Proposed exemption from the RIT-D - Primary distribution feeders

Option for consultation

We are considering the exclusion of investments required to address a network issue on a primary distribution feeder from the RIT-D.

Reasoning

DNSPs currently undertake a large volume of investments to augment primary distribution feeders and there is a risk that subjecting such investments to the RIT-D may impose a significant regulatory burden on DNSPs.

DNSPs would be required to report on any primary distribution feeders which have exceeded their normal cyclic rating under normal operating conditions in their DAPRs. The information that would be reported on would include:

- the location of the primary distribution feeder;
- the extent of overload experienced in the current year;
- the forecast load in the next 2 or 3 years and the extent the forecast load would exceed the normal cyclic rating (summer or winter); and
- any potential solutions being considered by the DNSP to address the overload.

This reporting regime would provide appropriate information transparency regarding DNSPs' decision making on their primary distribution feeders. The DAPRs would also provide non-network proponents with detailed information on the location and extent of potential constraints on these assets, should there be potential for non-network alternatives to address any arising constraints. In addition, the DNSP's Demand Side Engagement Strategy would outline the actions DNSPs would undertake in engaging with non-network proponents and assessing non-network proposals.

The DNSPs' DAPR and Demand Side Engagement Strategy would together provide appropriate safeguards to ensure DNSPs invest in primary distribution feeders in a transparent, efficient and technology neutral manner. Therefore, to ensure that the regulatory burden on DNSPs is proportionate to its potential benefits, we are considering the exclusion of primary distribution feeders from the RIT-D.

We seek stakeholder comments on the proposal to exclude primary distribution feeders from the RIT-D and the wording of the proposed exemption in section 2(a)(vii) of the framework specification in Appendix B.

4.5 Specification Threshold Test (STT)

Draft recommendation

DNSPs would be required to undertake the STT for all investments which are subject to the RIT-D.

Under the STT, DNSPs would be required to assess:

- The reasons for the investment;
- The material potential for the use of non-network options either to defer or remove the need for the investment to address the identified need; and
- The material potential for the identified need to adversely impact on the quality of service experienced by end use customers, including:
  - estimated changes in voluntary load curtailment by end use customers; and
  - estimated changes in involuntary load shedding and customer interruptions caused by network outages.

If the proposed investment does not meet the requirements of the STT, the DNSP would be required to publish the outcome and supporting reasons for their STT assessment and the investment would not be subject to the project specification stage of the RIT-D (but would still be subject to project assessment process). If the estimated capital cost of the most expensive distribution option which is both technically and economically feasible for meeting the need is less than $10 million, the DNSP would also not be required to publish and consult on a draft project assessment report.

If a proposed investment does meet the requirements of the STT, the DNSP would be required to publish its STT assessment in its project specification report during the project specification stage of the RIT-D (see section 4.6 below).

Reasoning for draft recommendation

The objective of the STT is to tailor the consultation and reporting requirements of the RIT-D to each identified need, to ensure consultation and reporting requirements are fit for purpose and proportionate to their potential benefits.

Attendees at the stakeholder workshop generally supported the proposed STT as a mechanism to filter proposed investments, but highlighted the need for a simple assessment which could be quickly and consistently applied. It was suggested at the workshop that if an identified need does not meet the STT requirements, the cost threshold for publishing a draft project assessment report should be set at $15 to $20 million.

EnergyAustralia's submission on the Stakeholder Workshop Paper supported the STT, noting that it was similar to the Demand Management Screening Test it currently undertakes to determine the feasibility of non-network options.[56]

[56] EnergyAustralia, Submission to the Stakeholder Workshop Paper, p. 2; ENA, Submission to the Stakeholder Workshop Paper, p. 5

However, submissions from SP AusNet and the Energy Networks Association raised concerns regarding the complexity of the overall design of the RIT-D framework. [57]

TEC's submission did not support the STT and suggested that the STT was non-transparent and would further limit the uptake of non-network solutions.[58]

The STT has been recommended to provide for a responsive and flexible RIT-D, which can be adjusted to meet the range of distribution investments undertaken by DNSPs. As discussed above, the STT assessment would work in conjunction with the cost threshold and scope of the RIT-D to determine the appropriate process for each proposed investment.

It would be appropriate for the STT to assess the material potential for non-network solutions and the material potential for the identified need to impact adversely on end use customers' quality of service. For investments where there was potential for non-network solutions, this would ensure that non-network proponents have an opportunity to put forward alternative proposals to address the identified need during the project specification stage. For investments where there may be an adverse impact on end users' quality of service, it would require DNSPs to undergo more extended consultation to ensure that the consumers that were likely to be affected are able to comment on the proposed investment.

We also considered that there was a need for the RIT-D to provide for a more streamlined process for small to medium sized investments where there was no potential for either non-network solutions or an adverse impact on end users' quality of service. This is to strike the right balance between the compliance cost on DNSPs and the benefits of additional consultation. Therefore, it is also proposed that investments which do not meet the requirements of the STT and where the most expensive investment option which is technically and economically feasible is less than $10 million, would also be exempt from the publication of a draft project assessment report.

We note concerns regarding the complexity of the overall RIT-D. In designing the STT and the broader RIT-D, we have sought to provide flexibility for the process to be tailored to the varied investments undertaken by DNSPs, and for the process to be proportionate in terms of its potential benefits. As a consequence of this more tailored approach, the RIT-D is necessarily more complex. However, it is considered that the potential benefits of the RIT-D design, in terms of more targeted consultation and reporting and reduced timeframes, are likely to outweigh the potential drawback of greater complexity. Further, consistent with its role as promulgator and enforcer of the RIT-D, the AER would be required to publish guidelines governing the application of the RIT-D, which would assist DNSPs and interested parties to understand how it would be applied.

We acknowledge that DNSPs have been provided with discretion to undertake the STT assessment and there is the potential for DNSPs to game this assessment to

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[57] SP AusNet, Submission to the Stakeholder Workshop Paper, p. 5.

[58] Total Environment Centre, Submission to the Stakeholder Workshop Paper, p. 6.

access a fast tracked RIT-D process. However, we consider that this risk is minimised by the proposed consultation and reporting requirements and the dispute resolution process.[59]

We seek stakeholder comments on the practical application of the STT and whether the STT provides an appropriate degree of discretion to DNSPs.

4.6 Project Specification stage

4.6.1 Requirements of the project specification report

Draft recommendation

Investments which meet the requirements of the STT would be subject to the project specification stage of the RIT-D**.** Under this stage, DNSPs would be required to consult on the identified need for the distribution investment through a project specification report.

The project specification report would contain the following information:

- a description of the identified need for the investment and the assumptions used in identifying the identified need;
- a summary of the DNSP's assessment of the identified need against the STT;
- the technical characteristics of the identified need that a non-network option would be required to deliver; and
- a description of all investment options to meet the identified need, including:
  - a technical definition or characteristics of the option;
  - estimated construction timetable and commissioning date; and
  - to the extent practicable, the total indicative capital and operational costs.

DNSPs would also be required to publish any preliminary or supplementary information where such information is likely to enhance the ability of interested parties to engage constructively on the project specification report.

Reasoning for draft recommendation

Only investments which meet the requirements of the STT would be subject to the project specification stage of the RIT-D. This would ensure that the process is

[59] For investments which are considered not to meet the STT and have an estimated capital cost of $10 million or more, DNSPs would also be required to report and publicly consult on a draft project assessment report

proportionate as only investments which are likely to benefit from additional reporting and consultation would be subject to this stage.

The project specification stage would require DNSPs to consult publicly on the range of options to meet the identified need and seek comments on any alternative options, both network and non-network. At this stage, non-network proponents would have an opportunity to put forward proposals to meet the identified need. This would reduce the likelihood that alternative credible options were overlooked in the project assessment process and would facilitate the discovery and adoption of the most efficient solution to the identified need. It would also facilitate a technology neutral approach to the project assessment process, consistent with the MCE's stated outcomes for the national framework.

The project specification report, in addition to each DNSPs' Demand Side Engagement Strategy, would provide transparency regarding the desired characteristics of a non-network proposal and how a DNSP would assess any non-network proposal it receives. This would improve communication between DNSPs and non-network proponents and facilitate the uptake of non-network solutions, where they are the most efficient option to address the identified need.

For investments which may have an adverse impact on the quality of service experienced by end users, DNSPs would be required to inform the public and consult on this impact through the project specification stage. This would ensure DNSPs' decision making processes were transparent and give affected parties an formal opportunity to comment on the proposed projects.

4.6.2 Accelerated consultation on project specification report

Draft recommendation

The project specification report would be published on DNSP website and circulated to that DNSP's register of interested parties within five business days of its publication.

DNSPs would provide interested parties with a minimum of 6 months to provide submissions on each project specification report. However, the consultation period on the project specification report may be reduced to a minimum of 1 month if DNSPs:

- constructively engaged with non-network proponents through its Demand Side Engagement Strategy on the identified need for the investment prior to undertaking the STT; and
- sought to identify scope for, and develop, alternative non-network options or variants to the identified investment options either internally or via consultation with non-network proponents.

DNSPs would be required to outline the basis on which they have complied with the Rules requirements for this accelerated consultation period in their project specification report, if they are seeking to consult under this timeframe.

Reasoning for draft recommendation

The MCE terms of reference requested the Commission examine the "perceived failure" of DNSPs to look at non-network alternatives in a neutral manner when making distribution augmentation assessments. Consistent with the terms of reference, the objective of the proposed opportunity for accelerated consultation on project specification reports is to encourage ongoing engagement between DNSPs and non-network proponents, and the consideration of non-network alternatives as part of DNSPs' day to day planning practices.

This opportunity for accelerated consultation on project specification reports was raised for discussion at the second stakeholder workshop. Attendees generally noted that if DNSPs have shown "reasonable endeavours" to seek non-network solutions, then they should be able to consult under an accelerated timeframe. Some attendees at the workshop considered that if DNSPs have undertaken prior consultation with non-network proponents and there had been no non-network options put forward that there should be no public consultation period on the project specification report. Attendees generally agreed that if DNSPs have not undertaken prior engagement with non-network proponents, that the consultation period on the project specification report should be 6 - 9 months.

Grid Australia's submission on the Stakeholder Workshop Paper noted that it was concerned that:

> …phrases such as "constructively engage" are ambiguous and that an objective assessment of meeting this requirement will be problematic... The framework proposed in the Specification is heavily weighted towards DNSPs seeking out non-network solutions. Grid Australia considers there could be more emphasis placed on providing incentives to non-network solution providers to identify opportunities early and engage with the DNSP earlier than at present.[60]

In contrast, TEC's submission stated that:

> Non-network providers already suffer from reduced time-frames to deliver proposals compared to the extended timeframes that networks have at their disposal to plan augmentation. As such they are already at a disadvantage compared to monopoly DNSPs. Reducing this timeframe even further at the discretion of DNSPs is inappropriate.[61]

[60] Grid Australia, Submission to the Stakeholder Workshop Paper, p. 3.

[61] Total Environment Centre, Submission to the Stakeholder Workshop Paper, p. 6.

The proposed opportunity for accelerated consultation would work in conjunction with the proposed Demand Side Engagement Strategy and DAPR, to facilitate and provide incentives for non-network engagement and the investigation of non-network options by DNSPs. However, this opportunity for accelerated consultation also places a complementary responsibility on non-network proponents to put forward proposals and engage proactively with DNSPs on an ongoing basis. Under the recommended proposal, DNSPs would not be penalised for consulting under an accelerated consultation period if after undertaking prior consultation with non-network proponents in accordance with the Rules, no non-network alternatives were proposed.

However, under the project assessment process, the absence of a proponent in itself would not be considered a reason for excluding an investment option from being a credible option. Therefore, if a DNSP identifies the potential for non-network solutions under the STT and no non-network proponents put forward a proposal for a non-network option during the project specification stage, the DNSP would still be required to consider the non-network option under the project assessment process and implement it if it is the most efficient option.

We are interested in stakeholder comments as to whether prescription is required in the Rules regarding the actions that DNSPs must have undertaken to qualify for accelerated consultation on their project specification reports. An alternative to greater prescription in the Rules would be to provide the AER with greater discretion in its development of the RIT-D Application Guidelines to determine the appropriate actions DNSPs must undertake to comply with the Rules requirements for accelerated consultation.

4.7 Project Assessment Process – Consideration of Market Benefits and Costs

Draft recommendation

The project assessment process would be undertaken by DNSPs following either:

- the publication of a STT report, for investments which did not meet the STT requirements; or
- the end of consultation on a project specification report, for investments which did meet the STT requirements.

Under the proposed project assessment process, DNSPs would be required to consider all applicable market benefits and costs in regards to each credible option. It is proposed that the market benefits that DNSPs would consider include:

- changes in voluntary load curtailment;
- changes in involuntary load shedding and customer interruptions caused by network outages, using a reasonable forecast of the value of electricity to customers;

- changes in the parties' costs, other than the DNSP's;
- differences in the timing of distribution investments;
- changes in transfer capability from the dispatch of embedded generating units;
- any additional option value (where this value has not already been included in the other classes or market benefits) gained or foregone from implementing the credible option with respect to the likely future investment needs of the market; and
- changes in electrical energy losses.

DNSPs would be provided with the option of quantifying applicable market benefits, where DNSPs consider that any market benefits are likely to be material or the quantification of market benefits was likely to alter the preferred solution to the identified need.

DNSPs would be required to consider and quantify all applicable costs in the Rules against each credible option. It is proposed that the costs that DNSPs would consider include:

- costs incurred in constructing or providing the credible option;
- operating and maintenance costs over the operating life of the credible option; and
- the cost of complying with laws, regulations and applicable administrative requirements in relation to each credible option.

DNSPs would also be able to consider any additional market benefits and costs which they consider to be relevant.

Reasoning for draft recommendation

The RIT-D should be supported by prescription in the Rules as to which classes of market benefits and costs should be considered during the project assessment process. This would promote greater consistency across the NEM in the application of the RIT-D, consistent with the principles for the national framework.

Submissions from SP AusNet and Grid Australia considered that the Rules should provide more limited market benefits, to reflect the types of market benefits which may support a distribution investment.[62]

Ergon Energy's submission questioned whether it was appropriate for the Rules to stipulate the market benefits and costs which should be considered under the RIT-D,

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62 SP AusNet, Submission to the Scoping and Issues Paper, p. 7; Grid Australia, Submission to the Scoping and Issues Paper, p. 4.

while EnergyAustralia indicated that it was unclear what market benefits distribution investments may deliver, beyond unserved energy. [63]

Submissions from non-network proponents such as the Alternative Energy Association, Energy Response and CUAC considered that a more extensive list of market benefits and costs should be considered under the RIT-D, including environmental benefits such as emissions savings and fuel use efficiency, to ensure non-network options can be appropriately valued.[64] To overcome timing constraints and to provide greater certainty to interested parties, the Alternative Energy Association and CUAC proposed that different non-network alternatives could be provided with a “proxy value” of market benefits.[65]

Our draft recommendations provide that a more limited list of market benefits should be considered under the RIT-D than what is required under the RIT-T, which is consistent with the characteristics of distribution investments.

The AER would be required to provide guidance on the range of market benefits for distribution and the appropriate methodologies for valuing market benefits and costs in the RIT-D Application Guidelines, which would provide DNSPs with certainty regarding the level of analysis required under the RIT-D to satisfy the Rules requirements.

We are interested in stakeholder comments regarding the list of market benefits and costs that DNSPs should consider under the RIT-D and whether it would be appropriate to require DNSPs to consider any market benefits and costs in addition to those currently proposed.

4.8 Publication of draft and final project assessment reports

Draft recommendation

DNSPs would be required to publish a draft project assessment report within 12 months of the following, where relevant:

- the end of consultation on a project specification report, for investments which meet the requirements of the STT; or
- the publication of a STT report, for investments which do not meet the requirements of the STT.

[63] Ergon Energy, Submission to the Scoping and Issues Paper, p. 12; EnergyAustralia, Submission to the Scoping and Issues paper, p. 7.

[64] See submissions on the Scoping and Issues Paper from: Alternative Energy Association, p. 5; Energy Response, p. 4; CUAC, p. 7.

[65] Alternative Energy Association, Submission to the Scoping and Issues Paper, p. 5; CUAC, Submission to the Scoping and Issues Paper, p. 7.

For proposed investments which do not meet the requirements of the STT and where the estimated capital cost of the most expensive investment option is less than $10 million, DNSPs would be exempt from publishing a draft project assessment report. For such investments, DNSPs would be required to publish their STT report and then their final project assessment report.

The draft project assessment report would contain:

- a description of each credible option assessed by the DNSP to meet the identified need;
- the DNSP's quantification of each applicable cost, and where relevant, each applicable market benefit, for each credible option;
- the results of a net present value analysis of each credible option;
- the identification of the proposed preferred option which maximises the net present value of economic benefits; and
- the technical characteristics, estimated construction timetable, and indicative capital and operational costs of the proposed preferred option.

DNSP would be required to publicly consult on the draft project assessment report for a period of not less than 30 business days.

DNSPs would be required to publish their final project assessment reports, as soon as practicable following the end of consultation on their draft project assessment report or the publication of their STT report. The final project assessment would outline each DNSP's final decision on the preferred solution, after taking into account, where relevant, the submissions received on the draft project assessment report.

For investments where the preferred solution has an estimated capital cost of $20 million or less, DNSPs could publish their final project assessment report as part of their DAPR, where the timing was appropriate.

Reasoning for draft recommendation

The objective of the draft and final project assessment reports would be to provide transparency to DNSPs' decision making processes, their consideration of the range of credible options to meet each identified need, and their assessment of the preferred option.

The consultation period on the draft project assessment report would provide interested parties with an opportunity to raise any concerns regarding DNSPs' assessment of credible options before DNSPs finalise their preferred option. The proposed minimum 30 business day consultation timeframe is aligned with the consultation timeframe for draft project assessment reports under the RIT-T. A specified minimum timeframe also provides DNSPs with a degree of certainty regarding the timing of the RIT-D process.

For investments where the preferred option has a capital cost of $20 million or less, DNSPs may publish their final project assessment report in their DAPR. This decreases the compliance cost for DNSPs, while ensuring that DNSPs publish final project assessment reports for large investments as soon as practicable after finalising their preferred option.

4.9 RIT-D and the AER determination process

Draft recommendation

The AER would be required to take into consideration DNSPs' application of the RIT-D and final project assessment reports when considering regulatory proposals under Chapter 6 of the Rules.

Reasoning for draft recommendation

The final project assessment reports would form one of many factors taken into account by the AER. The final project assessment report would contain substantial information on the economic justification of an investment, which would assist the AER in its revenue determinations. Providing a link between the RIT-D and the economic regulatory regime would also ensure that DNSPs apply rigour and scrutiny during their consideration and assessment of investment options during the RIT-D. This achieves the principles of transparency and economic efficiency.

4.10 Development of the RIT-D and RIT-D Application Guidelines

Draft recommendation

At the same time as the AER publishes a proposed RIT-D, the AER would also publish guidelines on the operation and application of the RIT-D and how disputes in relation to the application of the RIT-D would be addressed and resolved by the AER (the RIT-D Application Guidelines).

Among other information, the AER's RIT-D Application Guidelines would provide guidance and worked examples as to:

- the acceptable methodologies for undertaking the STT;
- the acceptable methodologies for valuing the costs and market benefits of an option;
- the suitable modelling periods and approaches to scenarios development;
- what may constitute an externality under the RIT-D;
- what constitutes a credible option;
- the appropriate approach to undertaking a sensitivity analysis;

- the appropriate approaches to assessing uncertainty and risks; and
- when a person is sufficiently committed to a credible option to be characterised as a proponent.

The AER would be provided with the option of publishing the RIT-D and RIT-D Application Guidelines in a single document with the RIT-T and the RIT-T Application Guidelines.

Reasoning for draft recommendation

Under the proposed RIT-D, there would be three distinct but complementary aspects which would govern its application:

- principles on how the RIT-D should be applied, which would be set out in the Rules;
- the RIT-D, which would be developed by the AER in accordance with the principles set out in the Rules; and
- guidelines for the operation and application of the RIT-D, which the AER would be required to develop and publish.

In submissions to the Scoping and Issues Paper, there was general support from both DNSPs and non-network proponents regarding a preference for high level principles to be set out in the Rules and for the AER's guidelines to relate to the application of the RIT-D, consistent with the principles in the Rules.[66]

As noted by EnergyAustralia:

> Guidelines should not be used as a substitute for clear policy that should be reflected in the Rules. Further it is critical that the AER is not charged with developing guidelines which impose substantive obligations on Distributors, which are also subject to enforcement by the AER.[67]

Consistent with the concerns raised in submissions and the approach adopted for the RIT-T, greater prescription on the procedure and framework for the new RIT–D is proposed for inclusion in the Rules. Under the proposed framework, the Rules would set out the principles that the AER must adopt in promulgating the test and the RIT-D guidelines. The purpose of this is to ensure that the RIT-D is applied in a consistent manner, which would provide a level of certainty and stability for DNSPs in undertaking new network investments, while leaving sufficient discretion for the AER to promulgate the test consistent with its role as the regulator. It would also provide the AER with sufficient flexibility in its development of the test. This flexibility will ensure the test can be amended in response to market developments

[66] See submissions on the Scoping and Issues Paper from: Jemena, p. 8; Integral Energy, p. 19; Total Environment Centre, p. 10; EnergyAustralia, p. 8; CUAC, p. 10; Energy Networks Association, p. 25.

[67] EnergyAustralia, Submission to the Scoping and Issues Paper, p. 8.

and that it remains appropriate to assess the range of investments undertaken by DNSPs.

A greater level of description and explanation on possible methodologies, supported by examples, should be contained within the AER's guidelines. This would assist DNSPs in their STT assessments and consideration of market benefits and costs, and improve the level of predictability for market participants in how RIT-D assessments are undertaken. A greater level of detail in the AER's guidelines will also clarify the actions that DNSPs must undertake in order to comply with the Rules requirements.

This strikes the appropriate balance between the Rules providing the appropriate framework to achieve the intended objectives for the RIT-D, and the regulator ensuring compliance with the Rules in the making and administration of the Test, so that the objectives of the national framework are achieved in practice. It would also meet the principles of greater consistency across the NEM and consistency with the arrangements for transmission.

The framework specifications provide the AER with the option of publishing the RIT-D, RIT-D guidelines, RIT-T, and RIT-T guidelines in a single document. This would provide for greater efficiency in the AER's processes and improved consistency between the RIT-D and the RIT-T. As discussed in chapter 1, it is considered that the RIT-D and RIT-D guidelines could be published by the AER 12 months following the publication of the final Rule for the national framework.

5 Dispute Resolution Process

The MCE has requested that the national framework include a dispute resolution process.

Currently, disputes related to the application of the Regulatory Test by DNSPs must be resolved under the dispute resolution process in Chapter 8 of the Rules. This process is general in nature and not tailored to the specific types of disputes that may be raised in relation to distribution planning. Also, this process is complex and has the potential to be lengthy and costly. As such, it is not considered appropriate for the dispute resolution process in Chapter 8 of the Rules to continue to apply to disputes related to the RIT-D process under the national framework.

This Chapter describes the proposed new dispute resolution process for distribution planning (a diagram outlining the proposed design is provided in Appendix D). In considering the appropriate design of an alternative dispute resolution mechanism, we have used the dispute resolution process developed for the RIT-T as the basis.

Summary of draft recommendations

18. The dispute resolution process would apply to all investments which are subject to the RIT-D.

19. The process would only apply to DNSPs' application of the RIT- D against the requirements in the Rules (i.e. compliance review) and cover all stages and decisions made by DNSPs when applying the RIT-D.

20. Registered Participants, the AEMC, Connection Applicants, Intending Participants and interested parties would able to raise a dispute under the proposed process.

21. The deadline for raising a disputes with the AER would be 30 business days following the publication of the DNSP's final project assessment report or the publication of the DNSP's DAPR, containing the final project assessment report.

22. The AER would either reject the dispute or make a determination on the dispute within 40-60 business days of receiving the dispute notice, depending on the complexity of the dispute. The AER can only be able to make a determination to direct the DNSP to amend its final project assessment report if:

- The DNSP has not correctly applied the RIT-D in accordance with the Rules; or

- The DNSP has made a manifest error in its calculations.

23. In making a determination on a dispute, the AER would specify the timeframe for the DNSP to amend its final project assessment report.

5.1 Purpose of the Dispute Resolution Process

The purpose of the dispute resolution process for the national framework is to provide an accessible and timely mechanism for interested parties to question DNSPs' decision making and, in doing so, make transparent DNSPs' decisions and apply a regulatory discipline on their behaviour.

The process should reflect good regulatory practice by being proportionate in its design, so that the costs of undertaking the process reflect its potential benefits. The costs associated with the process should also be efficient and the process itself should be balanced in its treatment of all parties to the dispute.

5.2 Scope of the Dispute Resolution Process

Draft recommendation

A single dispute resolution process would apply to all investments which are subject to the RIT-D. The dispute resolution process would be limited to a review of the DNSPs' compliance with the Rules in regards to their application of the RIT-D (i.e. a compliance review), rather than a merits review of DNSPs' decisions during the RIT-D process.

Disputes could be raised in relation to the application of the RIT-D process against the requirements in the Rules, including:

- the DNSP's assessment as to whether an identified need meets the STT;
- whether the DNSP has met the requirements for accelerated consultation on project specification reports;
- the DNSP's assessment of which investment options are credible options during the project assessment process;
- the DNSP's quantification of applicable costs against credible options; and
- the DNSP's assessment of the preferred option.

Disputes can not be raised with respect to:

- any matters treated as externalities by the RIT-D; or
- an individual's personal detriment or property rights.

Reasoning for draft recommendation

The scope of the dispute resolution process seeks to balance the need to provide an accessible mechanism to provide transparency to DNSPs' decision making and the need to ensure that DNSPs' planning processes and investments would not be unduly delayed.

Submissions on the Scoping and Issues Paper generally considered that the scope of the dispute resolution process should be restricted to the project assessment process under the RIT-D and that DAPRs should not be subject to dispute.[68] As noted by Integral Energy:

> To allow disputes to apply to matters arising from the annual planning process would be problematical. The annual planning process is a forward looking process and is intended to provide information to interested parties on the most likely scenarios in terms of the development of the distribution network. The APR is only provided to interested parties for information purposes only and a DNSP should not be held accountable for any decisions made by participants based on the information in the APR.[69]

It is not appropriate to extend the dispute resolution process to DNSPs' DAPRs as these reports represent forward looking plans by DNSPs based on forecasts of future scenarios, rather than commitments to undertake particular actions or investments. Sufficient business and regulatory drivers exist to ensure that DNSPs carry out appropriate planning and produce accurate forecasts in their DAPRs. Therefore, the scope of the dispute resolution process should be limited to the application of the RIT-D.

Compliance review, not merits review

Submissions from DNSPs considered that the dispute resolution process should only involve a compliance review of DNSPs' actions under the requirements of the Rules and should not involve a merits review of a DNSP's project assessment.

We recommend that the process should be limited to a review of DNSPs' compliance under the Rules to ensure DNSPs remain the ultimate decision makers as to which investments are constructed. It is not appropriate for the regulator (nor has the regulator the required expertise) to effectively take over the role of the network planner once a dispute has been raised. This approach is consistent with the scope of the dispute resolution process for transmission.

Scope of RIT-D projects subject to dispute resolution

Currently, disputes can only be raised in relation to the project evaluation reports for new large distribution assets (i.e. projects which will cost in excess of $10 million) or where the project would change the Registered Participant's DUOS charges by more than 2 per cent.[70] There was support from attendees at the second stakeholder workshop for the dispute resolution process to continue to only apply to the final project assessment reports under the RIT-D and for the process to also be restricted to investments above a defined threshold.

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68 See submissions on the Scoping and Issues Paper from: AER, p. 7; Integral Energy, pp. 16-17; ENA, p. 24; Country Energy, p. 12.

69 Integral Energy, Submission on Scoping and Issues Paper, p. 16.

70 cl. 5.6.2(i) of the National Electricity Rules.

The RIT-D process would provide a degree of discretion to DNSPs to determine a number of matters, such as:

- whether the identified need meets the STT requirements and consequently what level of reporting and consultation is required for proposed investments;
- whether appropriate prior engagement with non-network proponents has been conducted to allow project specification reports to be consulted on under an accelerated consultation period;
- whether any market benefits should be quantified; and
- which options were credible options.

Given this level of discretion, it is appropriate to balance this discretion by allowing parties to question DNSPs' decision making for all investments which are subject to the RIT-D. Furthermore, including all investments subject to the RIT-D within the scope of the dispute resolution process would ensure greater consistency in DNSPs' compliance with the requirements under the Rules. Imposing a higher threshold for the dispute resolution process has the potential to provide an incentive for DNSPs to be less stringent in their compliance with the RIT-D requirements for investments below the threshold. Furthermore, the dollar value of an investment does not necessarily reflect the impact or significance of the investment on the network.

We seek stakeholder comments on the proposed scope of the dispute resolution process.

5.3 Process for Raising a Dispute

Draft recommendation

Registered Participants, the AEMC, Connection Applicants, Intending Participants and interested parties should be able to raise a dispute under the proposed dispute resolution process.

Disputes should be raised with the AER in writing within 30 business days after the publication of DNSPs' final project assessment reports or the publication of DNSPs' DAPRs, containing their final project assessment reports.

Reasoning for draft recommendation

The process for raising a dispute under the national framework, seeks to be an accessible and timely mechanism for parties to question DNSPs' decision making and obtain decisions on outstanding issues which can not be resolved informally amongst the relevant parties.

Under the current arrangements, dispute resolution is only available to Registered Participants. Therefore, non-network proponents or other interested parties which are not Registered Participants are currently unable to raise disputes. Submissions on the Scoping and Issues Paper from non-network proponents including CUAC and Energy Response, highlighted the need for connection applicants and non-network proponents to be able to raise disputes.[71] A number of stakeholders also considered that the process for raising a dispute should be consistent with the dispute resolution process developed for the RIT-T. [72]

Consistent with the principles of transparency, economic efficiency and consistency with the transmission planning framework, any party which may be impacted by DNSPs' decisions under the RIT-D, including any non-network proponents, should be able to raise a dispute with the AER for resolution. Therefore, the scope of parties who can raise a dispute should be expanded to include the AEMC, Connection Applicants, Intending Participants and interested parties, as well as Registered Participants.

As noted above, the intention of the dispute resolution process is to provide a formal mechanism for parties to obtain decisions on matters only when such matters can not be resolved informally amongst the disputing parties. Parties should seek to resolve any issues or concerns, where possible, directly with DNSPs before raising a dispute with the AER. Parties would also be able to raise any concerns with DNSPs through the public consultation stages under the RIT-D process. Furthermore, DNSPs have an incentive to address any concerns held by interested parties before a dispute is raised with the AER, to ensure the timely implementation of their investments.

Requiring disputes to be raised within 30 business days following the publication of a final project assessment report, ensures that the RIT-D process is not subject to potential delays. It also provides DNSPs with greater certainty regarding the timing of their investments.

5.4 AER's Powers in Considering Disputes

Draft recommendation

Under the proposed dispute resolution process, after receiving a dispute notice, the AER would be required to make a decision either to:

- reject the dispute if the AER considers that the grounds for dispute are invalid, misconceived or lacking in substance; or
- make and publish a determination:
  - directing the DNSP to amend its final project assessment report and the timeframe by which it must amend this report; or
  - based on the grounds of the dispute, confirming that the DNSP would not be required to amend the final project assessment report.

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[71] See submissions on the Scoping and Issues Paper from: CUAC, p. 9; Energy Response, p. 4.

[72] See submissions on the Scoping and Issues Paper from: Integral Energy, p. 18; AER, pp. 13-14; Grid Australia, p. 5; ENA, p. 24.

The AER would make its decision within 40 business days of receiving a dispute notice. The time period to make its decision may be extended to 60 business days if the AER considers additional time is required due to the complexity of issues involved. In making a determination on the dispute, the AER may request further information from the DNSP or from the party bringing the dispute.

The AER would only make a determination to direct the DNSP to amend the matters set out in the final project assessment report if it determines that:

- the DNSP had not correctly applied the RIT-D in accordance with the National Electricity Rules; or
- there was a manifest error in the calculations performed by the DNSP in applying the RIT-D.

Reasoning for draft recommendation

We consider that the AER is the most appropriate body to assess disputes relating to the RIT-D. This would complement its functions as the regulator, enforcer and promulgator of the RIT-D. The proposed process for the consideration of disputes and the grounds on which the AER is able to request DNSPs amend their final project assessment reports, are consistent with the dispute process for the RIT-T. As noted above, submissions on the Scoping and Issues Paper generally considered that there should be consistency between the RIT-T and RIT-D dispute resolution processes, consistency between transmission and distribution arrangements would also meet the principles for the national framework.[73]

Timing for dispute resolution

To reflect the national framework's principles of promoting economic efficiency and proportionality, it is important that the dispute resolution does not unduly delay investments. Providing the AER with an opportunity to dismiss disputes which are misconceived or lacking in substance upon receiving a dispute notice, provides a safeguard against vexatious or baseless disputes. This would also ensure that disputes do not unnecessarily delay investments. Limiting the period for the AER to consider and make determinations on disputes to a maximum of 60 business days, would provide certainty to DNSPs regarding the timing of their investments.

[73] See submissions on the Scoping and Issues Paper from: Integral Energy, p. 18; AER, pp. 13-14; Grid Australia, p. 5; ENA, p. 24.

6 Observations on the Framework for Distribution Planning

This Review is recommending reforms to the annual planning, project assessment and reporting processes currently required of DNSPs. Other aspects of the regulatory regime influence distribution planning, and these aspects will affect the ability of the national framework to achieve the intended objectives. There could be significant benefits from moving these arrangements to a nationally consistent framework, as well.

This Chapter discusses other components of the regulatory regime where we suggest that further review and consistency is needed. The areas that we suggest could benefit from further review include:

- the process for the determination of jurisdictional reliability standards;
- the relevance and application of Schedule 5.1 of the Rules to distribution;
- target setting of and reporting on reliability performance; and
- asset management practices and reporting.

The reliability of the distribution network is of critical importance to the quality of the service provided to end customers. Disruptions to distribution networks are responsible for 90% of the duration of interruptions to customers.[74] Within that it is the radial and meshed networks of the medium voltage primary distribution systems (typically 11kV and 22 kV) that contribute about 75% of all minutes off supply to electricity customers. While this Review will assist the provision of reliability and the performance of the networks through increasing transparency, consistency and promoting economic investment, and review and reform of the areas listed above could make further contributions to ensuring safe, reliable and efficient network performance across the NEM.

Supporting background material on factors which influence the reliability and quality of supply is contained in Appendix E.

We would welcome any comments on market participants may have on the issues discussed in this Chapter.

6.1 The Process for the Determination of Jurisdiction Reliability Standards

The security of supply and reliability standards, set out in jurisdictional instruments, underpin how the annual planning processes are currently undertaken by the DNSPs. The SKM Background Report details the various reliability criteria and

[74] Australian Energy Regulator, 2008, State of the Energy Market 2008, November, p.156.

standards applicable in each jurisdiction and showed that a mixture of deterministic and probabilistic criteria are applied.[75]

The SKM Background Report highlights that the form, function of, and processes for setting reliability standards. It also discusses how the businesses interpret and comply with these standards vary significantly across the NEM. SKM Background Report stated that while it is difficult to make direct comparisons between different reliability criteria, there is no evidence that either deterministic or probabilistic criteria produces a superior outcome.[76]

Under probabilistic criteria, DNSPs may load certain system components above normal ratings based on a risk assessment which balances the annualised cost of augmentation against the probability weighted cost of energy not supplied, at the estimated community cost of loss of supply. This means that a certain proportion of their system will be loaded above normal ratings at peak load times.

Under deterministic criteria, commonly known as N-1, other DNSPs plan to have a level of redundancy built into critical parts of their system such that the unplanned loss of one component (usually the one with the highest rating) does not result in a loss of supply. The N-1 criterion is usually applied only to loads above a certain threshold, which may vary from 5MVA to 15MVA, depending on the particular circumstances. Even above these threshold there may be a period of loss of supply while automatic or manual switching is undertaken to restore supply. There are a number of “variants” of N-1, where supply is actually lost for a single contingency event.

We note that, due to factors such as areas of high load growth and capital and resource shortages, some DNSPs operate with parts of their systems in breach of their target N-1 criteria, such that it produces similar (but more random) outcomes to the application of probabilistic criteria.

The development of a national framework for electricity distribution network planning should take into consideration how the development and application of system security and planning criteria influences the planning processes. A number of issues arise from the current arrangements that may affect the objectives for the national framework:

- The lack of transparency and clarity of the methodology for determining and the processes for setting reliability standards may not allow network users, including embedded generation, to make the most efficient location decisions;

- The lack of consistency in the form and description of the reliability standards may lead to uncertainty for existing and potential market participants seeking to

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75 SKM Background Report, op cit.

76 SKM Background Report, p. 4.

understand the basis upon which a DNSP will make an investment. This may make it difficult for non-network businesses to operate on a NEM wide basis;

- The responsibilities for setting the reliability standards or for interpreting the standards tends to be delegated to DNSPs. This gives rise to questions of conflict of interest where DNSPs also have responsibility for planning and investment;

- How DNSPs comply with the reliability standards and the penalty for non-compliance are not clear; and

- There is a need for consistency between the reliability standards set at the distribution and transmission levels, especially given that often system limitations can be addressed by either a transmission option or a distribution option.

Harmonising the process and framework for determining the reliability planning standards that apply in each jurisdiction could deliver improvements in the reliability and security performance of distribution networks. Integrated and consistent standards for network planning and expansion may send clearer signals about the investment required to alleviate forecast capacity shortfalls. It may also signal more clearly the need for greater redundancy to reduce supply interruptions to consumers following security events. Also increasing the availability of information about network standards may encourage open discussion about their appropriateness and what is required to meet the standards.

The Commission, supported by the Reliability Panel, conducted a review into the jurisdictional reliability standards for transmission networks and provided advice to the MCE on the development of a nationally consistent framework for transmission reliability standards.[77] That review considered issues relating to transmission planning which are similar to those identified above. We suggest that there is justification for assessing the materiality of these issues for distribution, and that a similar review into distribution reliability standards be initiated.

6.2 The Relevance and Application of Schedule 5.1 of the Rules to Distribution

Schedule 5.1 of the Rules describes the planning, design and operating criteria that must be applied by NSPs to the networks which they own, operate or control. For distribution, mainly the quality of supply criteria are relevant.

We suggest that there are three possible issues where further work is needed:

- The criteria set out in Schedule 5.1 can lack specificity and can require a significant degree of interpretation. This provides DNSPs discretion in the application of their obligations to various points on the network;

[77] AEMC, Transmission Reliability Standards Review, Final Report to MCE, 30 September 2008.

- Aspects of Schedule 5.1 relate predominantly to transmission rather than distribution such as power transfer capability, credible contingency events, system stability, load shedding, blocking of auto-reclose, and continuous and dynamic ratings; and

- There is a need for the Schedule 5.1 standards to complement and support the jurisdictional standards.

As part of the review suggested in Section 6.1 above, Schedule 5.1 of the Rules should be considered in regards to its application and relevance to distribution and its ability to complement the jurisdictional instruments.

6.3 Reporting on and Target Setting of Reliability Performance

Jurisdictional regulators and responsible Government departments have set out reporting requirements and targets for end customer reliability and customer service standards for the DNSPs to comply with (e.g., System Annual Interruption Duration Index (SAIDI), System Annual Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI)). Appendix B of the SKM Background Report details the existing requirements.

Aspects of this are being transferred to the national framework under Chapter 6 of the Rules, and will become the responsibility of the AER. In June 2008 (and amended in May 2009), the AER published its design for Service Performance Target Incentive Scheme (SPTIS). [78]

While there is a requirement to monitor and report on reliability of supply in all jurisdictions, the level of reporting and the amount of detail provided varies dramatically from jurisdiction to jurisdiction. The highest level of detailed reporting is evident in Victoria, where there is a mandated bonus/penalty scheme in place (the S-factor scheme), while the lowest level of reporting is evident in the ACT where reporting of system reliability and quality is not required.

We recognise that significant advances have been made in recent years in refining, defining, and standardising the reporting of reliability statistics by the DNSPs in the NEM. However there are significant differences in the calculation and reporting of SAIDI, SAIFI and CAIDI. The most material differences are:

- Some DNSPs report only unplanned interruptions, while others report both planned and unplanned interruptions;

- Some DNSPs include individual customer installation faults (the fault being on the customers installation, not the DNSP's network), while others exclude them;

[78] Australian Energy Regulator, Electricity distribution network service providers Service target performance incentive scheme, Final Decision, June 2008, (amended in May 2009).

- Some DNSPs report statistics only at a system level, while others report to a more disaggregated level (e.g. CBD, urban, short rural, long rural);
- Some DNSPs also report reliability for poorly performing feeders, on an exception basis;
- Some DNSPs use the 2.5 beta (SAIDI) method for determining exclusions of extreme events, while others historically have not (most, if not all are currently moving towards the 2.5 beta method);
- In some cases, the targets set for particular zones/ regions do not closely align with average reliability actually delivered (e.g. some CBDs);
- In the case of Aurora (in Tasmania), reliability statistics relate only to the primary distribution systems (11 kV and 22 kV), not transmission / sub-transmission; and
- In most states, DNSPs report on both planned and unplanned outages, while in New South Wales, DNSPs are required to report only on unplanned outages. The disadvantage of reporting only unplanned outages is that it is then difficult, if not impossible, to assess the effectiveness with which other strategies, such as live line working and using mobile generators, are being utilised.

Likewise, the level of disaggregation of target setting for distribution reliability varies significantly from DNSP to DNSP (See Appendix B of the SKM Background Report). In regards to specific target setting, either at a total system level, or disaggregated to the CBD, urban, short rural and long rural level, it is notable that some of the targets are based on somewhat dated historical figures (e.g. ActewAGL), and some targets (e.g. CBDs) do not appear to bear any similarity to recent actual performance.

Further, targets are set in some cases to encourage and reward improved performance, whereas other targets are relatively fixed for a certain period, or are set on the basis of ensuring a high probability of achievement. In these cases there is little incentive for DNSPs to achieve continued improvement in reliability performance over time.

These differences between existing distribution reliability statistical calculations and levels of jurisdictional reporting and target setting are material. This makes it difficult for market participants to understand and compare performance across the NEM. There is a material risk that the current jurisdiction differences will lead to inefficient investment or unbalanced investment between reliability improvement and other competing investment needs.

While we recognise that changing and adapting computer systems and their associated data collection processes can be difficult and costly, we recommended that a more consistent approach is required in the monitoring and reporting of reliability performance, and in the setting of future reliability targets. We understand that the AER is pursuing work in this area as part of its setting of the reliability service targets and we would encourage them to continue to pursue this and to seek greater consistency across the NEM.

6.4 Asset Management

A key element in the development of sound planning processes and system performance for distribution is for the DNSP to have in place well structured asset management philosophies and principles

Asset management encompasses more than routine inspection and maintenance practices to ensure that assets remain in a safe, serviceable and reliable condition. In the context of electricity distribution, asset management covers the development and implementation of plans and processes, encompassing management, financial, consumer, engineering, information technology and other business inputs to:

- assess and record the nature, location, condition and performance of its distribution system assets;
- develop and implement plans for the acquisition, creation, maintenance, operation, refurbishment, repair and disposal of its distribution system assets;
- ensure that the level of service provided to consumers through the use of its distribution assets meets the business's internal targets and its regulatory and statutory obligations;
- minimise the risks associated with the failure or reduced performance of assets; and
- develop, test or simulate and implement contingency plans to deal with events which have a low probability of occurring, but are realistic and would have a substantial impact on consumers;

in a way which minimises costs to consumers over the expected life cycle of the assets.[79]

Asset management practices work in tandem with the forward looking annual planning process and both need to be understood to obtain a clear picture of how DNSPs plan, invest in and maintain their networks. Clearly, asset management is playing an increasingly important role in the business models, current levels of reliability and performance, and ultimate sustainability of DNSPs' performance in the NEM. This is especially the case for networks which are incurring, or expecting, a high level of replacement and refurbishment expenditure.

We understand that over the previous ten years, DNSPs have made significant progress in developing sophisticated business models and asset management processes. However, there are currently differences in the understanding and application of asset management principles and practices. In addition, there are

[79] Parsons Brinckerhoff Associates, *Electricity Distribution Business Asset Management Plans and Consumer Engagement: Best Practice Recommendations*, Prepared for Commerce Commission NZ, April 2005, p. 37.

significant differences in the reporting requirements relating to businesses asset management practises. Some jurisdictions do not require DNSPs to publish asset management processes, while in those jurisdictions which do, the reporting requirements differ significantly.

There could be benefit in establishing minimum 'best practice' criteria for asset management. This would impose on all DNSPs a minimum level of discipline to ensure that they make focused and adequately planned investment decisions and that services are provided at the appropriate level of quality. Best practice criteria would assist to achieve a minimum level of consistency across the NEM.

We also suggest that a common reporting requirement for asset management is applied across the NEM. A common asset management report published by DNSPs would greatly support the common annual planning reports produced under the national framework. It would provide end users with the opportunity to understand how DNSPs conduct their asset management and to assess how that impacts on their quality of service. It would also enable external stakeholders, including the AER, to assess the effectiveness and maturity of asset management decisions made by DNSPs, including the quality of service provided and level of planned investment, on an on-going basis.

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A Draft Framework Specification - Annual Planning Process and Reporting

The purpose of these specifications is to explain in detail, the regulatory requirements for the proposed annual planning process and reporting requirements under the national framework, as set out in the draft recommendations. The specifications are not draft Rules and should not be interpreted as such.

Definitions

Existing definitions in the Rules have been italicised in these specifications. In addition, a number of new terms for the national framework have also been italicised. Outlined below are the new terms that have been included in these specifications and an accompanying proposed definition for each new term.

asset management

The development and implementation of plans and processes, encompassing management, financial, consumer, engineering, information technology and other business inputs to ensure assets achieve the expected level of performance and minimise costs to consumers over the expected life cycle of the assets.[80]

joint network investment

An investment identified under clause 3(b) which affects both a *transmission network* and *distribution network* or an investment which would require action by the *Transmission Network Service Provider* and the *Distribution Network Service Provider*.

primary distribution feeder

Distribution line 11kV or greater.

sub transmission asset

Substation or switching station connected with a primary voltage 33kV or greater and is not a *transmission* asset.

system limitation

A limitation on the *transmission network* and/or *distribution network* as identified under clause 2(b) or clause 6(d) of this specification.

[80] Gives consideration to the discussions on asset management in *Electricity Distribution Business Asset Management Plans and Consumer Engagement: Best Practice Recommendations*, prepared for Commerce Commission NZ by Parsons Brinckerhoff Associates, April 2005.

1. Objectives of the Annual Planning Process and Reporting

The objectives of the Annual Planning Process and Reporting are to:

(a) provide a clearly defined and efficient planning process which provides certainty in relation to the approval of network expansion and augmentation to maintain the security and reliability of the electricity supply to consumers;

(b) ensure efficient development of the network, including to ensure that non-network alternatives are considered in a neutral manner;

(c) provide appropriate information transparency;

(d) ensure a level playing field for all regions in terms of attracting investment and promoting more efficient decisions;

(e) ensure that network users understand how the timing and location of connections might affect capability of the network and the need for augmentations; and

(f) reduce the regulatory compliance burden for participants operating in more than one region in the NEM.

2. Scope of the Annual Planning Process

(a) Each *Distribution Network Service Provider* shall carry out an annual planning process analysing the expected future operation of its *network* over a minimum forward planning period.

(b) The minimum forward planning period for the purpose of the annual planning process is 5 years for *distribution* and *sub transmission networks* and 10 years for *transmission networks*.

(c) The annual planning process shall apply to all *distribution network* assets and activities undertaken that would be expected to have a material impact on the *distribution networks* and *sub transmission networks* in the forward planning period (which would include negotiated services and replacement activities).

3. Requirements of the Annual Planning Process

(a) The Annual Planning Process shall require each *Distribution Network Service Provider*, for its *network*, to at a minimum:

(i) prepare forecasts, to the best of its ability, of maximum demands for distribution feeders, sub-transmission substations, zone substations, and at a system level having consideration of;

1. number of customer connections at a system level;

2. energy consumption at a system level;

3. level of embedded generation;

(ii) based on the outcomes of the forecasts in clause 3(a)(i), identify *system limitations*[81] on its *network*;

[81] "System limitation" is defined in accordance with the provisions in clause 7.d.

(iii) identify the need for investments and options available to address the *system limitations*, and to carry out the requirements of the *Regulatory Investment Test for Distribution* or the *Regulatory Investment Test for Transmission* and the *Demand Side Engagement Strategy* where appropriate;

(iv) undertake the annual planning process in a manner which is consistent with its *asset management* policies; and

(v) take into account any other jurisdictional specific requirements.

(b) The Annual Planning Process shall require each *Distribution Network Service Provider* to undertake joint planning with each *Transmission Network Service Provider* of the *transmission networks* to which the *Distribution Network Service Provider's distribution networks* are connected.

(i) The joint planning will require the *Transmission Network Service Provider* and the *Distribution Network Service Providers* to meet on a regular and as required basis to assess the adequacy of existing transmission-distribution connection points over the next five years and to undertake joint planning of proposals which relate to both networks.

(ii) The parties shall use best endeavours to work together to ensure efficient planning outcomes and to identify the most efficient investments.

(iii) The joint planning will identify any system limitations that will affect both the *transmission networks* and *distribution networks* or will require coordination by both the *Distribution Network Service Provider* and *Transmission Network Service Provider* to undertake action to address a *system limitation*.

(iv) Where the necessity for augmentation or a non-network alternative is identified by the process under this clause, the *Network Service Providers*:

1. must jointly determine plans that can be considered by relevant *Registered Participants*, *AEMO* and *interested parties*;
2. must carry out the *Regulatory Investment Test for Transmission* for the options identified;[82] and
3. may agree on a lead party to be responsible for carrying out the *Regulatory Investment Test for Transmission*. In this case, the other parties will be deemed to have discharged their obligations to undertake the relevant *Regulatory Investment Test* in response to the identified need for investment.

[82] As the RIT-T would apply, joint investments would be subject to the RIT-T threshold, which is currently $5m. For joint investments between $2 and $5, the RIT-T would still need to be carried out but the projects would be exempt from the specification and draft report requirements.

(c) The Annual Planning Process shall require *Distribution Network Service Providers* to meet regularly to undertake joint planning with other *Distribution Network Service Providers* where there is a requirement to do so to consider any augmentation or non-network alternative that affects more than one *distribution network*.

(d) The Annual Planning Process shall require each *Distribution Network Service Provider* to use reasonable endeavours to engage with non-network proponents and consider non-network alternatives. This shall include the requirement for each *Distribution Network Service Provider* to implement a *Demand Side Engagement Strategy*.

4. Demand Side Engagement Strategy[83]

(a) The objective of the *Demand Side Engagement Strategy* is to provide transparency regarding the consideration and assessment of non-network solutions by *Distribution Network Service Providers*. This would encourage the engagement of non-network proponents in network planning and streamline the development process to improve efficiency and provide certainty over the recovery of investments.

(b) Each *Distribution Network Service Provider* must prepare and make available a *Demand Side Engagement Facilitation Process* document which shall set out at a minimum:

(i) the process which the *Distribution Network Service Provider* follows to develop, investigate, assess and report on potential non-network solutions;

(ii) the process with which the *Distribution Network Service Provider* follows to engage and consult with potential non-network proponents to determine their level of interest and ability to participate in the development process;

(iii) an outline of the process with which the *Distribution Network Service Provider* follows to negotiate with non-network proponents to further develop a potential solution;

(iv) an outline of the information a non-network proponent is to include in a non-network solution proposal;

(v) an outline of the criteria that a potential non-network proponent should meet or consider in any offers or proposals;

(vi) an outline of the principles that the *Distribution Network Service Provider* considers in developing the payment levels for non-network solutions;

(vii) a reference to any applicable incentive payment schemes for the implementation of non-network solutions and whether any specific

[83] The Demand Side Engagement Strategy replaces the "Non-network Strategy" discussed in the Workshop Paper.

criteria is applied by the *Distribution Network Service Provider* in its application and assessment of the scheme;

(viii) sources of relevant, publicly available information that non-network proponents may access;

(ix) how non-network proponents may contact the *Distribution Network Service Provider* to request additional information or register as an interested party;

(x) the process, including the information that would be provided, for updating the parties registered on the *Register of Interested Parties*;

(xi) the *Distribution Network Service Provider's* contact details; and

(xii) the methodology to be used for determining *avoided Customer TUOS charges*, in accordance with clause 5.5 and clause 5.6.2(k1) of the *Rules*.

(c) The *Demand Side Engagement Facilitation Process* document shall be published by 31 December 2010.

(d) The *Distribution Network Service Provider* shall review its *Demand Side Engagement Facilitation Process document* at least once every three years.

(e) Each *Distribution Network Service Provider* must establish and maintain a public database of non-network proposals and/or case studies that demonstrate the economic assessments undertaken by the *Distribution Network Service Provider* in its consideration of non-network proposals.[84] In selecting items to be published in the database, the *Distribution Network Service Provider* shall not breach any confidentiality provisions or publish any information that is commercially sensitive.

(f) Each *Distribution Network Service Provider* must establish and maintain a *Register of Interested Parties* for those parties wishing to be advised of developments relating to specific constraints.

5. Distribution Annual Planning Report

(a) By 31 December each year, each *Distribution Network Service Provider* must publish, and make available to interested parties, the *Distribution Annual Planning Report* setting out the outcomes from carrying out the annual planning process for the forward planning period beginning 1 January the following year.

(b) Within two months following the publication of the *Distribution Annual Planning Report*, the *Distribution Network Service Provider* must conduct a public forum on the *Distribution Annual Planning Report*.

(c) The *Distribution Annual Planning Report* must be certified by the Chief Executive Officer, and a Director or Company Secretary of the *Distribution Network Service Provider* that:

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[84] The database should include examples of proposals that were successful as well as examples of proposals that were not successful.

(i) the *Distribution Annual Planning Report* meets the *Distribution Network Service Provider's* obligations under the *Rules* and any other applicable *regulatory instruments*; and

(ii) the *Distribution Annual Planning Report* accurately represents the relevant policies of the *Distribution Network Service Provider*.

(d) The scope of *Distribution Annual Planning Report* is limited to *direct control services* and *system limitations* affecting the *power system* [and any significant investments in metering systems] only.

6. Contents of the Distribution Annual Planning Report

The *Distribution Annual Planning Report* must set out information on the following:

(a) *Distribution Network Service Provider* and *network*, including:

(i) description of the *network*;

(ii) description of the operating environment;

(iii) types of assets and the number of each type of asset;

(iv) planning methodology used, including the methodology used to identify the need for investments and the assumptions applied; and

(v) analysis and explanation of any aspects of the *Distribution Annual Planning Report* that has changed significantly from previous results (e.g. changes in forecast load);

(b) Forecasts for the forward planning period, including at a minimum:

(i) description of the forecasting methodology used; sources of input information; and the assumptions applied;

(ii) forecasts for the network as a whole; major connection points (including any transmission connection points); zone substations; sub-transmission assets; including:

1. total capacity;
2. firm delivery capacity (summer and winter);

(iii) load forecasts for the network as a whole; major connection points (including any transmission connection points); zone substations; sub-transmission assets; including:

1. peak load (summer and winter);
2. power factor at time of peak load;
3. load sharing/load transfer capabilities including transmission interface capacity; and
4. level of embedded generation;

(iv) forecasts of future connection points and zone substations, including location, future loadings, and estimated timing (month, year) of the connections;

(v) forecasts of reliability targets at a system level and by feeder categories; and

(vi) forecasts of any factors that may have a major affect on the *network*, including factors affecting:

1. fault levels;
2. voltage levels;
3. other system security requirements; and
4. ageing and potentially unreliable assets;

(c) *Primary distribution feeders* that have exceeded, in the current year or is forecast to exceed in the next 2 years, 100% of its normal cyclic rating (summer or winter) under normal operating conditions and identify:

(i) the location of the primary distribution feeder;

(ii) the extent of overload experienced in the current year;

(iii) the forecast load in the next 2 years and the extent the forecast load would exceed the normal cyclic rating (summer or winter); and

(iv) any potential solutions being considered by the DNSP to address the overload; and

(v) where an estimated reduction in forecast load would defer a forecast overload for a period of 12 months, include:[85]

1. the year and month in which the overload (the *system limitation*) is forecast to occur;
2. the relevant connection points at which the estimated reduction in forecast load may occur;
3. the estimated reduction in forecast load in MW needed;

(d) *System limitations* and network transfer capability, including at a minimum:

(i) identifying any system limitations for sub transmission assets and zone substations where the limitation may be caused by one or more of the following factors:

1. forecast load exceeding system capability; in which case identify: the extent of the overload; frequency of overload; duration of overload; power factor at time of peak load;
2. the requirement for asset replacement or refurbishment;
3. the requirement for system security or reliability improvement;
4. design fault levels being exceeded;
5. the requirement for voltage regulation;

[85] This clause is consistent with the clause introduced under the National Electricity Amendment (Demand Management) Rule 2009 No. 11. Additional information on this Rule change may be found at www.aemc.gov.au.

6. the requirement to meet SAIDI and SAIFI or any other regulatory obligations;

(ii) the location and estimated timing (month, year) of the system limitation;

(iii) analysis of any potential load transfer capability between supply points that may decrease the impact of the system limitation or defer the requirement for investment;

(iv) impact of the system limitation, if any, on the capacity at the transmission connection points;

(v) discussion of the potential solutions that may address the system limitation in the forward planning period, if a solution is required;

(vi) other jurisdictional requirements[86]; and

(vii) where an estimated reduction in forecast load would defer a forecast system limitation for a period of 12 months, include:[87]

1. the year and month in which a system limitation is forecast to occur (as required under (ii) above);

2. the relevant connection points at which the estimated reduction in forecast load may occur;

3. the estimated reduction in forecast load in MW needed;

(e) Provide a summary of each proposed *new distribution network investment* for which the *Regulatory Investment Test for Distribution* has been completed or is in progress, which may include:

(i) a summary of the outcomes or progress of the *Regulatory Investment Test for Distribution* including any consultation undertaken under the *Demand Side Engagement Strategy* or any other consultation on the investment;

(ii) a description of the investment required and how it will alleviate the system limitation;

(iii) estimated timing (month, year) of the investment;

(iv) the estimated total capitalised expenditure;

(v) a summary of any other options considered and, if the *Regulatory Investment Test for Distribution* is in progress, the *Distribution Network Service Provider's* preferred option and the reasons for selecting the preferred option;

(vi) any factors that may result in the investment requirements (or preferred option) being altered; and

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86 e.g. worst performing feeder analysis required in QLD.

87 This clause is consistent with the clause introduced under the National Electricity Amendment (Demand Management) Rule 2009 No. 11. Additional information on this Rule change may be found at www.aemc.gov.au.

(vii) any impacts on network users, including any potential material impacts on connection charges and distribution use of system charges that may be estimated;

(f) For each identified system limitation which will require a *Regulatory Investment Test for Distribution* an estimation of the date when the business intend to commence the *Regulatory Investment Test for Distribution*;

(g) For all committed projects with an estimated total capital cost of $2m or more that are urgent and unforseen projects, or refurbishment or replacement projects provide:

(i) a brief description of the project, including location;

(ii) the date or estimated time (month, year) the investment was or would become operational;

(iii) the purpose of the investment;

(iv) the total capital cost of the investment; and

(v) an explanation of the ranking of any reasonable credible options to the committed project which are being or have been considered by the *Distribution Network Service Provider*. These alternatives could include, but are not limited to, generation options, demand side options, and options involving other *distribution* or *transmission networks*.

(h) Joint planning undertaken with the *Transmission Network Service Provider,* including:[88]

(i) a summary of the process and methodology used by the *Network Service Providers* to undertake joint planning;

(ii) any planned *joint network investments*; and

(iii) where additional information on the joint planning and *joint network investments* may be obtained;

(i) Joint planning undertaken with other *Distribution Network Service Providers* where applicable, including:

(i) a summary of the process and methodology used by the *Distribution Network Service Providers* to undertake joint planning;

(ii) any planned investments that have been discussed through this process, including estimated capital costs and estimated timing (month, year) of the investment; and

(iii) where additional information on the investments may be obtained.

(j) Performance of the *network*, including a summary description of the:[89]

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[88] It is noted that there may be changes to the provisions in the Rules governing TNSP planning requirements. These provisions will need to be reviewed and reconciled for consistency.

[89] The potential benefits of including the information in the planning report is to provide transparency, clarity and context for the system limitation and investment requirements. If the information is

(i) *reliability standards* that apply, including the relevant codes, standards and guidelines;

(ii) the *quality of supply standards* that apply, including the relevant codes, standards and guidelines;

(iii) performance of the *distribution network* against the *reliability* and *quality of supply standards* for the preceding year; and

(iv) qualitative assessment of how the *Distribution Network Service Provider* has complied with the applicable standards; its processes to ensure compliance; and a description of any areas of the standards that were not met in the preceding year and the corrective action taken.

(k) Asset Management:

(i) Summary of any *asset management* strategy employed by the *Distribution Network Service Provider*;

(ii) summary of any issues that may impact on the *system limitations* identified in the *Distribution Annual Planning Report* that has been identified through carrying out *asset management*; and

(iii) information about where further information on the *asset management* strategy and methodology adopted by the *Distribution Network Service Provider* may be obtained.

(l) Any other information as required by the relevant jurisdiction.

reported elsewhere, it could potentially be replicated here at limited additional cost. However, it is noted that different timing requirements for reporting may impact the replication of information.

B Draft Framework Specifications- Regulatory Investment Test for Distribution and Dispute Resolution Process

The purpose of these specifications is to explain in detail, the regulatory requirements for the proposed RIT-D and dispute resolution process under the national framework, as set out in the draft recommendations. The specifications are not draft Rules and should not be interpreted as such.

Definitions

Existing definitions in the Rules have been italicised in these specifications. In addition, a number of proposed new terms for the national framework have also been italicised. Outlined below are the new terms that have been included in these specifications and an accompanying proposed definition for each new term.

draft project assessment report

The report prepared by a *Distribution Network Service Provider* under section 8.

final project assessment report

The report prepared by a *Distribution Network Service Provider* under section 10.

project specification report

The report prepared by a *Distribution Network Service Provider* under section 7.

Regulatory Investment Test for Distribution

The test developed and published by the AER under section 1, as in force from time to time, and includes amendments made under section 12.

Regulatory Investment Test for Distribution Application Guidelines

The guidelines developed and published by the AER under section 12, as in force from time to time, and includes amendments made under section 12.

Specification Threshold Test

The test undertaken by a *Distribution Network Service Provider* under section 6.

specification threshold test report

The report prepared by a *Distribution Network Service Provider* under section 6(c)(ii).

In addition, a number of terms have been defined in the Rules for the new RIT-T[90] which are proposed to be amended to also refer to investments considered under the RIT-D. These terms include:

cost threshold

cost threshold determination

cost threshold review

credible option

dispute notice

identified need

preferred option

reliability corrective action

1. Objectives of the Regulatory Investments Test for Distribution

(a) The *AER* must develop and publish the *Regulatory Investment Test for Distribution* in accordance with the *distribution consultation procedure*.

(b) The purpose of the *Regulatory Investment Test for Distribution* is to identify the *credible option* that maximises the present value of net economic benefits to all those who produce, consume and transport electricity in the *market* (the *preferred option*).

(c) For the avoidance of doubt, a *preferred option* may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the identified need is for *reliability corrective action*.

(d) This should not prevent a *Distribution Network Service Provider* from applying a value of *unserved energy* (probabilistic planning) approach to the project assessment if it wishes to do so.

(e) The *Regulatory Investment Test for Distribution* will involve a consideration of both costs and benefits associated with all of the *credible options.*

(f) Market benefits may be quantified by the *Distribution Network Service Provider* under the *Regulatory Investment Test for Distribution* where the *Distribution Network Service Provider* considers it appropriate to do so.

[90] AEMC, 2009, National Electricity Amendment (Regulatory Investment Test for Transmission) Rule 2009 No. 15, 25 June 2009.

(g) The *Regulatory Investment Test for Distribution* shall comprise three sequential stages: a *Specification Threshold Test* stage; a project specification stage; and a project assessment stage.

(h) The extent of consultation and the nature of assessment required will vary depending upon the specific characteristics of the identified need in question. This will be achieved through a combination of cost thresholds and the *Specification Threshold Test.*

(i) The *Regulatory Investment Test for Distribution* should permit the single assessment of an integrated set of related and similar *distribution* investments.

(j) The *Regulatory Investment Test for Distribution* must:

(i) be based upon a cost-benefit analysis of the future that is to include an assessment of reasonable scenarios of future supply and demand if each *credible option* were implemented compared to the situation where no option is implemented;

(ii) not require the level of analysis to be disproportionate to the scale and likely impact of each of the *credible options* being considered; and

(iii) be capable of being applied in a predictable, transparent and consistent manner.

2. Scope of Projects Subject to the Regulatory Investment Test for Distribution

(a) A *Distribution Network Service Provider* must apply the *Regulatory Investment Test for Distribution* as part of the consideration of any new *distribution* investment, where the purpose of the *distribution* investment is to augment a *distribution* network, except in circumstances where:

(i) the proposed investment is required to address an urgent and unforeseen *network* issue that would otherwise put at risk the *reliability* of the *distribution network* as described in section 2c);

(ii) the estimated capital cost of the most expensive investment option, which is economically and technically feasible is less than $[2] million (as varied in accordance with a *cost threshold determination*);

(iii) the proposed investment is designed to ensure that a *transmission network* meets the level required by the minimum *power system security and reliability standards*. For the avoidance of doubt, such investments shall be assessed under the *Regulatory Investment Test for Transmission;*

(iv) The need for the proposed investment has been identified through a joint planning process between a *Distribution Network Service Provider* and a *Transmission Network Service Provider*;

(v) The cost of the proposed investment is to be fully recovered through charges in relation to *negotiated distribution services, alternative control services,* or unclassified *distribution services*;

(vi) The proposed investment will be a *connection asset*, which will not be part of the *Distribution Network Service Provider's* shared *distribution network*;

(vii) [The proposed investment is designed to address a *network* issue on a *primary distribution feeder*];

(viii) The *distribution* investment is related to the refurbishment or replacement of existing assets and is not intended to *augment* the *distribution network*; or

(ix) The refurbishment or replacement expenditure also results in an *augmentation* to the *network*, and the estimated capital cost for the *augmentation* component of the *distribution investment* is less than $[2] million (as varied in accordance with a *cost threshold determination)*, as allocated by the *Distribution Network Service Provider* in accordance with recognised *cost allocation methods* and any applicable *AER* guidelines.

(b) If the proposed *distribution* investment is to be provided as a *dual function asset,* the proposed investment shall be assessed under the *Regulatory Investment Test for Distribution.*

(c) For the purposes of section 2(a)(i), a proposed investment will be required to address an urgent and unforeseen *network* issue that would otherwise put at risk the *reliability* of the *distribution network* if:

(i) the proposed investment is required to be operational within 6 months of the *Distribution Network Service Provider* identifying the *identified need*; and

(ii) the event or circumstances causing the *identified need* was not reasonably foreseeable by, and was beyond the reasonable control of, the *Distribution Network Service Provider*; and

(iii) a failure to address the *identified need* is likely to materially adversely affect the *reliability* and *secure operating state* of the *distribution network*.

(d) A *Distribution Network Service Provider* must not treat different parts of an integrated set of related and similar proposed investments to an *identified need* as distinct and separate options for the purposes of determining whether the *Regulatory Investment Test for Distribution* applies to each of those distribution investments.

3. Application of the Regulatory Investment Test for Distribution – Identification of a credible options

(a) A *credible option* is an option (or group of options) that:

(i) addresses the *identified need*;

(ii) is (or are) economically and technically feasible;

(iii) can be implemented in sufficient time to meet the *identified need*; and

(iv) is (or are) identified as a *credible option* in accordance with section 3(b).

(b) In applying the *Regulatory Investment Test for Distribution*, a *Distribution Network Service Provider* must consider, in relation to a proposed *distribution investment* to address an *identified need*, other than those described in sections 2(a)(i)-(ix), all options that could reasonably be classified as *credible options*, taking into account:

(i) energy source;

(ii) technology;

(iii) ownership;

(iv) whether it is a network or non-network option;

(v) whether the *credible* option is intended to be regulated;

(vi) whether the *credible option* has a proponent; and

(vii) any other factor the *Distribution Network Service Provider* reasonably considers should be taken into account.

(c) The absence of a proponent does not exclude a *distribution* investment option from being considered a *credible option.*

4. Application of the Regulatory Investment Test for Distribution – Consideration of Market Benefits and Costs

(a) The *Regulatory Investment Test for Distribution* must require *Distribution Network Service Providers* to consider the following classes of market benefits that could be delivered by each *credible option*:

(i) changes in voluntary *load* curtailment;

(ii) changes in involuntary *load shedding* and customer interruptions caused by *network* outages, using a reasonable forecast of the value of electricity to consumers;

(iii) changes in costs for parties', other than *Distribution Network Service Provider* due to:

1. differences in the timing of new plant;
2. differences in capital costs; and
3. differences in the operational and maintenance costs.

(iv) differences in the timing of *distribution* investments;

(v) changes in the transfer capability in the dispatch of *embedded generating units*;

(vi) any additional option value (where this value has not already been included in the other classes or market benefits) gained or foregone from implementing the *credible option* with respect to the likely future investment needs of the *market*;

(vii) changes in *electrical energy losses*; and

(viii) any other market benefits that are determined to be relevant by the Distribution Network Service Provider, as consistent with section 4(f).

(b) *Distribution Network Service Providers* may quantify each applicable class of market benefit outlined in section 4(a) in respect to each *credible option*, where the *Distribution Network Service Provider* considers that any applicable market benefits may be material or where it considers the quantification of market benefits may alter the selection of the *preferred option*.

(c) With respect to the classes of market benefits outlined in sections 4(a)(i) and (ii), if the *credible option* is for *reliability corrective action*, the consideration and quantification assessment of these classes of market benefits will only apply insofar as the market benefits delivered by the *credible option* exceeds the minimum standards required for *reliability corrective action*.

(d) The *Regulatory Investment Test for Distribution* must require *Distribution Network Service Providers* to consider the following classes of costs that could be delivered by each *credible option*:

(i) costs incurred in constructing or providing the *credible option*;

(ii) operating and maintenance costs over the operating life of the *credible option*;

(iii) the cost of complying with laws, regulations and applicable administrative requirements in relation to the construction and operation of the *credible option*; and

(iv) any other costs that have been determined to be relevant by the *Distribution Network Service Provider,* as consistent with section 4(f).

(e) The *Regulatory Investment Test for Distribution* must include a quantification of all classes of costs outlined in section 4(d) for each *credible option*, unless the *Distribution Network Service Provider* provides an explanation in its *draft project assessment report* and *final project assessment report* which outlines why a particular class of cost is not expected to apply to a *credible option.*

(f) Any cost or market benefit which cannot be measured as a cost or market benefit to *Generators*, *Distribution Network Service Provider*s, *Transmission Network Service Providers*, *Market Customers*, and consumers of electricity may not be included in any analysis under the *Regulatory Investment Test for Distribution*.

(g) Any judgement by a *Distribution Network Service Provider* of whether a particular class of market benefit or cost applies to a *credible option* must be exercised in a manner which is objective and have regard to any submissions received on the *project specification report* and/or the *draft project assessment report*.

(h) The *Regulatory Investment Test for Distribution* shall, as a minimum, list or specify:

(i) the method or methods permitted for estimating the magnitude of the different classes of market benefits;

(ii) the method or methods permitted for estimating the magnitude of the different classes of costs;

(iii) the appropriate method and value for specific inputs, where relevant, for determining the discount rate(s) to be applied;

(iv) specify that a sensitivity analysis is required of any modelling relating to the cost-benefit analysis; and

(v) reflect that the *credible option* that maximises the present value of net economic benefit to all those who produce, consume or transport electricity in the *market* may, in some circumstances, be a negative net economic benefit (that is, a net economic cost) where the identified need is for *reliability corrective action* or where the *Distribution Network Service Provider* does not quantify market benefits during the project assessment process.

5. Review of Costs Thresholds

(a) Every 3 years (or shorter for the first review) the *AER* must undertake a review (the *cost threshold review*) of the changes in the input costs used to calculate the estimated capital costs in relation to investments subject to the *Regulatory Investment Test for Distribution* and the *cost threshold* for refurbishment, replacement, and urgent and unforeseen investments subject to the *Distribution Annual Planning Report*, for the purposes of determining whether the amounts (each *cost threshold*) needs to be changed to maintain the appropriateness of the *cost thresholds* over time by adjusting those *cost thresholds* to reflect any increase or decrease in the input costs since:

(i) [insert commencement date of Rule] in respect of the first *cost threshold review;* and

(ii) the date of the previous review in respect of every subsequent *cost threshold review.*

(b) Each c*ost threshold review* is to be commenced by the *AER* on 31 July of the relevant year.

(c) The AER must initiate its first *cost threshold review* in 2012.

(d) Within 6 weeks following the commencement of a *cost threshold review*, the *AER* must publish a draft determination outlining:

(i) whether the *AER* has formed the view that any of the *cost thresholds* need to be amended to reflect increases or decreases in the input costs to ensure that the appropriateness of the *cost thresholds* is maintained over time;

(ii) its reasons for determining whether the *cost thresholds* need to be varied to reflect increases or decreases in the input costs;

(iii) if there is to be a variation in a *cost threshold*, the amount of the new *cost threshold* and the date the new *cost threshold* will take effect; and

(iv) its reasons for determining the amount of the new *cost threshold*.

(e) At the same time as it publishes the draft determination under section 5(d), the *AER* must publish a notice seeking submissions on the draft determination and which specifies the period within which written submissions can be made (the *cost threshold consultation period)* which must be within 5 weeks from the date of the notice.

(f) The *AER* must consider any written submissions received during the *cost threshold consultation period* in making its final determination in respect of the matters outlined in section 5(d).

(g) This final determination must be made and published by the *AER* within 5 weeks following the end of the cost threshold consultation period (the *cost threshold determination*)

(h) The *AER* shall undertake its *cost threshold review* for the *Regulatory Investment Test for Distribution* at the same time it undertakes its *cost threshold review* for the *Regulatory Investment Test for Transmission.*

6. Regulatory Investment Test for Distribution Process- Specification Threshold Test stage

(a) The *Specification Threshold Test* stage shall be initiated by a *Distribution Network Service Provider's* assessment of an *identified need* for a proposed investment against the *Specification Threshold Test*.

(b) In undertaking the *Specification Threshold Test*, the *Distribution Network Service Provider* must assess the:

(i) reasons (*identified need*) for the proposed investment, including the assumptions used in identifying the *identified need*;

(ii) the material potential for the use of non-network options either to defer or remove the need for the proposed investment to address the *identified need*; and

(iii) the material potential for the *identified need* have an adverse impact on the quality of service experienced by end use customers, including:

1. estimated changes in voluntary *load* curtailment by end use customers; and

2. estimated changes in involuntary *load* shedding and customer interruptions caused by *network* outages.

(c) If after undertaking the *Specification Threshold Test* the *Distribution Network Service Provider* determines that:

(i) the identified need has:

1. no material potential for non-network options either to defer or remove the need for the proposed investment to address the *identified need*; and

2. no material potential to impact adversely on the quality of service experienced by end use customers,

then the *Distribution Network Service Provider*:

(ii) must publish a *Specification Threshold Test report* on its website which outlines its assessment against the *Specification Threshold Test* and the methodologies and assumptions used to make this assessment, as soon as practicable after the completion of the assessment. The *Specification Threshold Test report* must also be circulated to the *Distribution Network Service Provider's Register of Interested Parties* within 5 business days of the publication of the report on the *Distribution Network Service Provider's* website; and

(iii) is not required to publish a *project specification report* in accordance with section 7(d).

7. Regulatory Investment Test for Distribution Process - Project specification stage

(a) The project specification stage shall be initiated by a *Specification Threshold Test* assessment by a Distribution Network Service Provider which determines that:

(i) the identified need has:

1. material potential for non-network options either to defer or remove the need for the proposed investment to address the identified need; or

2. material potential to impact adversely on the quality of service experienced by end use customers.

(b) A *Distribution Network Service Provider* will be required to consult on the *identified need* for the proposed investment through the publication of a *project specification report*.

(c) The *project specification report* must contain the following information:

(i) a description of the *identified need*;

(ii) the assumptions used in identifying the *identified need* (including, in the case of proposed *reliability corrective action*, why the *Distribution Network Service Provider* considers *reliability corrective action* is necessary);

(iii) a summary of the *Distribution Network Service Provider*'s assessment of the *identified need* against the *Specification Threshold Test*, including:

1. the material potential for the use of non-network options either to defer or remove the need for the proposed investment to address the *identified need*;

2. the material potential for the *identified need* to impact adversely on the quality of service experienced by end use customers; and

3. the methodology and assumptions used by the *Distribution Network Service Provider* in undertaking the *Specification Threshold Test.*

(iv) the technical characteristics of the *identified need* that a non-network option would be required to deliver, such as:

1. the size of l*oad* reduction or additional supply;

2. location;

3. contribution to *power system security* or *reliability*;

4. contribution to system fault level; and

5. operating profile;

(v) a description of all options. These options can include, but are not limited to, alternative *distribution* options, *generation* options, demand side management, and options involving other *transmission* and *distribution networks* and could include groups of credible options; and

(vi) for each option, the *Distribution Network Service Provider* must provide information on:

1. A technical definition or characteristics of the option;

2. Estimated construction timetable and commissioning date where the option is a *network investment* option; and

3. To the extent practicable, the total indicative capital and operational costs.

(d) The *project specification report* shall be published on the *Distribution Network Service Provider's* website in a timely manner having regard to the ability of interested parties to identify the scope for, and develop, alternative investment options or variants to the proposed investment options.

(e) The *project specification report* must be circulated to the *Distribution Network Service Provider's Register of Interested Parties* within 5 business days of the publication of the report on the *Distribution Network Service Provider's* website.

(f) A *Distribution Network Service Provider* must publish any preliminary or supplementary information where such information is likely to enhance the ability of interested parties to engage constructively in the *project specification report* consultation process.

(g) Interested parties must be provided with not less than 6 months to make submissions on each *project specification report*. If the *Distribution Network Service Provider* has:

(i) constructively engaged with non-network proponents through its *Demand Side Engagement Strategy* on the *identified need* for the investment prior to undertaking the *Specification Threshold Test*; and

(ii) sought to identify scope for, and develop, alternative non-network options or variants to the proposed investment options either internally or via consultation with non-network proponents;

then interested parties must be provided with not less than 1 month to make submissions on the *project specification report.* *Distribution Network Service Providers* must outline the basis on which it is has adhered to sections 7(g)(i) and (ii) in its *project specification report* if it seeks to consult under this accelerated timeframe.

8. Regulatory Investment Test for Distribution Process – Draft project assessment report

(a) If the *Distribution Network Service Provider* elects to proceed with the proposed investment, within 12 months, or such longer time period as is agreed to in writing by the *AER*, of where relevant, the end of the consultation period on a *project specification report* or the publication by the *Distribution Network Service Provider* of a *Specification Threshold Test report*, the *Distribution Network Service Provider* must publish a *draft project assessment report* on its website.

(b) The *draft project assessment report* must be circulated to the *Distribution Network Service Provider*'s *Register of Interested Parties* within five business days of the publication of the report on the *Distribution Network Service Provider's* website.

(c) The *draft project assessment report* must include the following:

(i) a description of the *identified need* for the investment,

(ii) the assumptions used in identifying the *identified need* (including, in the case of proposed *reliability corrective action*, why the *Distribution Network Service Provider* considers *reliability corrective action* is necessary);

(iii) if applicable, a summary of, and commentary on, the submissions to the *project specification report;*

(iv) a description of each *credible option* assessed;

(v) where relevant, a quantification of each applicable market benefit for each *credible option*;

(vi) a quantification of each applicable cost for each *credible option*, including a breakdown of operating and capital expenditure;

(vii) a detailed description of the methodologies used in quantifying each class of cost and market benefit;

(viii) where relevant, the reasons why the *Distribution Network Service Provider* has determined that a class or classes of market benefits or costs do not apply to a *credible option*;

(ix) the results of a net present value analysis of each *credible option* and accompanying explanatory statements regarding the results;

(x) the identification of the proposed *preferred option*; and

(xi) for the proposed *preferred option*, the *Distribution Network Service Provider* must provide:

1. Details of the technical characteristics;

2. The estimated construction timetable and commissioning date;

3. Indicative capital and operational cost; and

4. A statement and accompanying detailed analysis that the *preferred option* satisfies the *Regulatory Investment Test for Distribution.*

(d) The *Distribution Network Service Provider* must seek submissions from *Registered Participants* and *interested parties* on the *preferred option* presented, and the issues addressed, in the *draft project assessment report.*

(e) The consultation period on the *draft project assessment report* must not be less than 30 business days from the publication date of the report.

(f) Within 4 weeks of the end of the consultation period on the *draft project assessment report*, at the request of an *interested party* or a *Registered Participant*, the *Distribution Network Service Provider* must use its best endeavours to meet with the *interested party* if:

(i) having considered all submissions, the *Distribution Network Service Provider*, acting reasonably, considers that the meeting is necessary or desirable; or

(ii) a meeting is requested by two or more *interested parties.*

9. Regulatory Investment Test for Distribution Process – Exemption from the draft project assessment report

(a) A *Distribution Network Service Provider* is exempt from publishing a *draft project assessment report* under section 8(a) if:

(i) the *Distribution Network Service Provider* has published a *Specification Threshold Test report* which determined that:

1. there is:

a. no material potential for non-network options either to defer or remove the need for the proposed investment to address the *identified need*; and

b. no material potential for the *identified need* to impact adversely on the quality of service experienced by end use customers; and

(ii) the estimated capital cost of the most expensive investment option which is both economically and technically feasible for meeting the *identified need* is less than $10 million (varied in accordance with a *cost threshold determination*).

10. Regulatory Investment Test for Distribution Process – Final project assessment report

(a) As soon as practicable after the end of the consultation period on the *draft project assessment report*, the *Distribution Network Service Provider* must, having regard to any submissions received on the *draft project assessment report*, publish a *final project assessment report* on its website.

(b) If the proposed investment is exempt from the *draft project assessment report* stage under section 9(a), the *Distribution Network Service Provider* must publish the *final project assessment report* on its website as soon as practicable after the publication of the relevant *Specification Threshold Test report*.

(c) The *final project assessment report* must be circulated to the *Distribution Network Service Provider*'s *Register of Interested Parties* within five business days of the publication of the report on the *Distribution Network Service Provider's* website.

(d) The *final project assessment report* must set out:

(i) the matters detailed in the *draft project assessment report* as required under section 8(c); and

(ii) summarise any submissions received from interested parties on the *draft project assessment report* and the *Distribution Network Service Provider's* response to each such submission.

(e) If the *preferred option* outlined in the *final project assessment report* has an estimated capital cost of $20 million or less, the *Distribution Network Service Provider* may discharge its obligations to publish its *final project assessment report* under sections 10(a) and (b) by including the *final project assessment report* as part of its *Distribution Annual Planning Report*.

(f) The AER shall take into account a *Distribution Network Service Provider's* application of the *Regulatory Investment Test for Distribution* and *final project assessment reports* when considering a *Distribution Network Service Provider's regulatory proposal* under Chapter 6 of the *National Electricity Rules.*

11. Dispute Resolution Process

(a) *Registered Participants*, the *AEMC, Connection Applicants, Intending Participants,* and *interested parties* may, by notice to the *AER*, dispute conclusions made by the *Distribution Network Service Provider* in the final project assessment report in relation to the application of the *Regulatory Investment Test for Distribution*.

(b) A dispute may not be raised in relation to any matters set out in the *final project assessment report* which:

(i) are treated as externalities by the *Regulatory Investment Test for Distribution*; or

(ii) relate to an individual's personal detriment or property rights.

(c) A person disputing a *final project assessment report* must within 30 business days after the publication of the *final project assessment report* or the publication of a *Distribution Annual Planning Report* containing the *final project assessment report:*

(i) give notice of the dispute in writing setting out the grounds for the dispute (the *dispute notice*) with the *AER*; and

(ii) at the same time give a copy of the *dispute notice* to the relevant *Distribution Network Service Provider*.

(d) Within 40 business days after receiving the *dispute notice* or within an additional period of up to 60 business days where the AER notifies interested parties that the additional time is required to make a determination because of the complexity or difficulty of the issues involved, the AER must either:

(i) reject any dispute by written notice to the person who initiated the dispute if the *AER* considers that the grounds for dispute are invalid, misconceived or lacking in substance;

(ii) notify the *Distribution Network Service Provider* that the dispute has been rejected; or

(iii) make and publish a determination, subject to section 11(f):

1. directing the *Distribution Network Service Provider* to amend the matters set out in the *final project assessment report*; or

2. stating that, based on the grounds of the dispute, the *Distribution Network Service Provider* will not be required to amend the *final project assessment report.*

(e) A *Distribution Network Service Provider* must comply with an *AER* determination made under section 11(d)(iii) within a timeframe proposed by the *AER* in its determination.

(f) In making a determination on the dispute, the AER:

(i) must only take into account information and analysis that the *Distribution Network Service Provider* could reasonably be expected to have considered or undertaken at the time that it performed the *Regulatory Investment Test for Distribution*;

(ii) must publish its reasons for making a determination;

(iii) may disregard any matter raised by a party in the dispute that is misconceived or lacking in substance;

(iv) may request further information from a party bringing a dispute, or from the *Distribution Network Service Provider,* in which case the period of time for rejecting a dispute or issuing a determination under section 11(d)(iii) is extended by the time it takes the relevant party to provide the requested further information to the *AER;* and

(v) where making a determination under section 11(d)(iii)(1), must specify a reasonable timeframe for the *Distribution Network Service Provider* to comply with the *AER's* direction to amend the matters set out in the *final project assessment report*.

(g) The *AER* may only make a determination under section 11(d)(iii) to direct the *Distribution Network Service Provider* to amend the matters set out in the *final* p*roject assessment report,* if it determines that:

(i) the *Distribution Network Service Provider* has not correctly applied the *Regulatory Investment Test for Distribution* in accordance with the *Rules*; or

(ii) there was a manifest error in the calculations performed by the *Distribution Network Service Provider* in applying the *Regulatory Investment Test for Distribution*.

(h) A disputing party or the *Distribution Network Service Provider* (as the case may be) must as soon as reasonably practicable provide any information requested under section 11(f)(iv) to the *AER*.

(i) The relevant period of time in which the *AER* must make a determination under section 11(d)(iii) is automatically extended by the period of time taken by the *Distribution Network Service Provider* or a disputing party to provide any additional information requested by the *AER*, provided:

(i) the *AER* makes the request for the additional information at least 7 business days prior to the expiry of the relevant period; and

(ii) the *Distribution Network Service Provider* or the disputing party provides the additional information within 14 business days of receipt of the request.

12. Regulatory Investment Test for Distribution Guidelines

(a) At the same time as the *AER* develops and publishes a proposed *Regulatory Investment Test for Distribution* under the *distribution consultation procedure*, the AER must also develop and publish guidelines for the operation and application of the *Regulatory Investment Test for Distribution* (*the Regulatory*

Investment Test for Distribution Application Guidelines) in accordance with the *distribution consultation procedure* and this section.

(b) The *Regulatory Investment Test for Distribution Application Guidelines* must:

(i) give effect to and be consistent with this section;

(ii) provide guidance on:

1. the operation and application of the *Regulatory Investment Test for Distribution*;

2. the process to be followed in applying the *Regulatory Investment Test for Distribution*; and

3. how disputes raised in relation to the application of the *Regulatory Investment Test for Distribution* and its application will be addressed and resolved by the *AER*.

(c) The *Regulatory Investment Test for Distribution Application Guidelines* must provide guidance and worked examples as to:

(i) the acceptable methodologies for undertaking the *Specification Threshold Test;*

(ii) the acceptable methodologies for valuing the costs of an option;

(iii) the suitable modelling periods and approaches to scenarios development;

(iv) what may constitute an externality under the *Regulatory Investment Test for Distribution;*

(v) the acceptable methodologies for valuing the *market* benefits of an option,

(vi) what constitutes a *credible option*;

(vii) the appropriate approach to undertaking a sensitivity analysis;

(viii) the appropriate approaches to assessing uncertainty and risks; and

(ix) when a person is sufficiently committed to a *credible option* to be characterised as a proponent under section 3(c).

(d) The *AER* must develop and publish the revised *Regulatory Investment Test for Distribution* and *Regulatory Investment Test for Distribution Application Guidelines* by [insert date] and there must be a *Regulatory Investment Test for Distribution* and *Regulatory Investment Test for Distribution Application Guidelines* in force at all times after that date.

(e) The *AER* may, from time to time and in accordance with the *distribution consultation procedure*, amend or replace the *Regulatory Investment Test for Distribution* and *Regulatory Investment Test for Distribution Application Guidelines* developed and published under this section, provided that such amendments must be published at the same time.

(f) The *AER* may publish the *Regulatory Investment Test for Distribution*, the *Regulatory Investment Test for Distribution Application Guidelines,* the *Regulatory Investment Test for Transmission* and the *Regulatory Investment Test for Transmission Application Guidelines* in a single document.

C Related AEMC Reviews and Rule changes

There are a number of current policy reviews and Rule changes that relate to the arrangements for distribution network planning. We will manage the various interactions between this Review and other work-streams as we conduct our assessment of the appropriate national framework. This Review will incorporate, where relevant, the outcomes of our Reviews into Demand Side Participation, Climate Change, and Extreme Weather Events.

The following areas of work, some of which were cited explicitly in the MCE's terms of reference, are relevant to this Review.

C.1 Review of Demand Side Participation in the NEM

We are currently undertaking a review into Demand Side Participation (DSP) in the NEM. The objective of this review is to determine whether there are barriers or disincentives within the Rules for the efficient uptake of DSP in the NEM. Part of this DSP Review will assess whether there are any barriers to the uptake of non-network investments within the current arrangements for distribution network planning.

The Draft Report on the DSP Review was published on 29 April 2009.[91] In the DSP Draft Report, it was noted that probabilistic planning standards are likely to be more consistent with the efficient use of DSP as they appear to be more amenable to handling DSP with different degrees of 'firmness'. The DSP Draft Report also highlighted that variability in network planning and consultation processes across DNSPs is likely to increase the costs associated with operating across the NEM for non-network proponents.

C.2 Demand Management Rule Change

On 23 April 2009, the Commission published its final Rule determination on Total Environment Centre's Demand Management Rule change proposal and determined to make the proposed Rule with some modifications.[92] The Rule change proposal sought to increase the requirements and incentives for the use of demand management in the NEM. The Rule as Made:

- Requires TNSPs to provide specific information in their Annual Planning Reports about forecast constraints, where an estimated reduction in forecast load would defer a forecast constraint; and

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[91] AEMC 2009, *Review of Demand-Side Participation in the National Electricity Market, Stage 2: Draft Report,* 29 April 2009, Sydney.

[92] AEMC 2009, *National Electricity (Demand Management) Rule 2009, Rule Determination,* 23 April 2009, Sydney and *National Electricity Amendment (Demand Management) Rule 2009, No. 11*, 23 April 2009, Sydney.

- Requires the AER to consider the extent that TNSPs have made provision for appropriate efficient non-network alternatives, when it assesses revenue proposals. To assist the AER in this task, TNSPs must provide information on the appropriate non-network alternatives they have considered in their revenue proposals.

The Rule as Made commenced operation on 1 July 2009.

C.3 Review of Energy Market Frameworks in light of Climate Change Policies

The MCE has directed the Commission to undertake a review to determine whether the existing energy market frameworks should be amended to accommodate the introduction of the Carbon Pollution Reduction Scheme (CPRS) and the expanded 20 per cent Renewable Energy Target (RET). This review is to consider both the electricity and gas markets across all states and territories. The outcomes of this review are to provide advice on what, if any, changes are needed to energy market frameworks, including how these changes should be implemented. The 2nd Interim Report to this review, which set out our proposed options for changes to energy market frameworks, was published on 30 June 2009.[93]

This Review will be particularly important for the consideration of demand management, as the CPRS and expanded RET will impact on the potential costs and benefits of demand side solutions in the NEM. Also there is a need to ensure that the project assessment process for distribution is consistent with climate change policies and especially whether the process appropriately values carbon costs.

C.4 Review of Effectiveness of NEM Security and Reliability Arrangements in light of Extreme Weather Events

On 28 April 2009, MCE directed the Commission to conduct a review of the effectiveness of NEM security and reliability arrangements in light of extreme weather events. Under the MCE's terms of reference, we were required to report on measures that are currently under consideration that would improve system reliability and security, and any further cost-effective measures that could be taken in the short term that would impact on system reliability for the summer of 2009-10. This report was provided to the MCE on 1 June 2009.

The report is to also consider any cost-effective changes that could be made to energy market frameworks to improve system reliability in the longer term and contribute to the more effective management of system reliability during future extreme weather events. This report is to be provided to the MCE by 30 October 2009. The MCE will determine whether the AEMC's reports will be published.

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93 AEMC 2009, *Review of Energy Market Frameworks in light of Climate Change Policies: 2nd Interim Report*, 30 June 2009, Sydney.

The MCE has requested that the Commission's advice be provided in relation to generation and transmission networks. While the MCE notes that the performance standards of distribution networks are the responsibility of the jurisdictions, the MCE's terms of reference also requests that the Commission provide any advice which would ensure network security and reliability.

C.5 Regulatory Test Thresholds and Information Disclosure on Network Replacements Rule change

On 23 October 2008, the Commission published *Regulatory Test Thresholds and Information Disclosure on Network Replacements, Rule Determination* and Rule as Made on the Rule change proposed by Grid Australia's Regulatory.[94] The effect of the Rule as Made has been to:

- raise the new small transmission network asset threshold from $1 million to $5 million and the new large transmission network asset threshold from $10 million to $20 million;
- provide for a three yearly review of threshold values by the AER; and
- require the following information to be provided on all proposed replacement transmission assets over $5 million in TNSPs' Annual Planning Reports: the purpose of the proposed asset; a list of alternative projects; and the TNSPs' estimated total capitalised expenditure on the proposed asset.[95]

As part of this Rule change, the Commission also considered aligning the revised new transmission network asset thresholds to the thresholds for new distribution network assets. However, while noting the applicability to distribution of many issues in the Rule change proposal, the Commission considered that the appropriate thresholds for distribution should be subject to separate analysis and consultation, particularly as the scope for demand side projects is greater for distribution than for transmission.

The Rule as Made commenced operation on 23 October 2008.

C.6 Regulatory Investment Test for Transmission Rule change proposal

On 20 February 2009, the Commission received a Rule change proposals from the MCE, seeking to implement a revised Regulatory Investment Test for Transmission (RIT-T), to improve the identification of transmission investment options which maximise net economic benefits. This Rule change proposal was recommended to

[94] AEMC 2008, *Regulatory Test Thresholds and Information Disclosure on Network Replacements, Rule Determination*, 23 October 2008, Sydney and *National Electricity Amendment (Regulatory Test Thresholds and Information Disclosure on Network Replacements) Rule 2008 No. 9*, 23 October 2008, Sydney.

[95] At the time the Rule change proposal was submitted, only network augmentations were subject to information disclosure requirements.

the MCE by the Commission in its Final Report on the National Transmission Planning Arrangements in June 2008.[96]

On 25 June 2009, the Commission published *Regulatory Investment Test for Transmission, Final Rule Determination* on the RIT-T Rule change proposal and determined to make the corresponding Rule.[97] Under the Rule as Made, the revised RIT-T: will:

- only apply when the capital cost of investment options exceed $5 million in value, with the exception of urgent or unforeseen investments, investments related to the provision of connection or negotiated services, and transmission projects which only involve replacements;
- amalgamate the reliability and market benefits limbs of the current regulatory test;
- facilitate earlier consultation in the planning process to enable other potential viable non-network options to be identified and assessed appropriately;
- ensure that national market benefits are recognised under the project assessment process; and
- include an additional market benefit category of option value, to recognise the benefits that the proposed project may have on future investments and costs.[98]

The Rule as Made commenced on 1 July 2009. Under the Rule as Made, the AER will be required to publish the RIT-T and RIT-T Application Guidelines by 1 July 2010.

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96 AEMC 2008, *National Transmission Planning Arrangements, Final Report to MCE,* 30 June 2008, Sydney.

97 AEMC 2009, *Regulatory Investment Test for Transmission, Final Rule Determination*, 25 June 2009, Sydney and *National Electricity Amendment (Regulatory Investment Test for Transmission) Rule 2009 No. 15*, 25 June 2009, Sydney.

98 Ibid.

D Comparison of Jurisdictional Reporting Requirements with the Draft Framework

The current jurisdictional requirements for reporting on the planning process are set out in the table below. A comparison of these obligations with the reporting requirements under the draft recommendations (Draft Framework) is also outlined.

The Draft Framework captures the existing jurisdictional reporting requirements, with the exception of the following points. These issues are also discussed in Chapter 3.

- The jurisdictions require reporting on historical information. Given the planning document is a forward looking document to identify investment and connection opportunities and that historical information is included in other reporting requirements, the Draft Framework includes the requirement to report on a summary of the performance of the network for the preceding year only.
- Some of the jurisdictional requirements relating to operational processes and procedures have not been included in the Draft Framework. It was considered that operational procedures and reporting (such as reporting on the adherence to safety procedures) were outside the scope of planning.
- Some of the jurisdictions require regional development plans. The Draft Framework does not include specific requirements for regional development plans as it focuses on system limitations according to asset class. However, the Draft Framework includes the requirement to identify the location of the system limitation. Load forecasts at the system level are also required. We are seeking comments on whether regional development plans should be included in the national framework.

Requirements in the Draft Framework that are in addition to the existing jurisdictional requirements are outlined below. These issues are discussed in more detail in Chapter 2 and Chapter 3.

- The Draft Framework requires DNSPs to establish and implement a Demand Side Engagement Strategy. Comparable obligations currently exist in NSW and SA only. However, it is noted that DNSPs in the other jurisdictions are required to consider potential demand management and embedded generation solutions in carrying out their planning.
- The Draft Framework clarifies the requirements for: forecasting; identifying and reporting on system limitations (or constraints); and reporting on projects and investments.
- The Draft Framework requires DNSPs to conduct a public forum following the publication of the DAPR. Certification of the DAPR by the CEO and a Director or Company Secretary would also required. Currently, no DNSPs conduct public forums and certification by the CEO is only required in QLD.
- The Draft Framework also clarifies the joint planning provisions and changes the requirements such that joint investments would be assessed under the RIT-T.

Summary of the Current Distributor Planning Requirements (compared with the Draft Framework)[99]

	QLD	NSW	VIC	SA	TAS
Regulatory Instruments[100]	Queensland Electricity Industry Code	Relevant Acts and Regulations	Electricity Distribution Code	ESCOSA Guideline No. 12	Tasmanian Electricity Code
Planning requirements	*Plan covering the next 5 years.* DNSPs to produce a Network Management Plan (NMP) under the code to set out how the DNSP is to manage and develop its supply network. (This requirement is included in the Draft Framework .) Additional plans – The regulator may request DNSPs to prepare a "summer preparedness plan". (No specific provisions are made for this requirement however, the Draft Framework require DNSPs to take account of summer (and winter) peak conditions.)	*Network management plan unspecified period. Demand management plan covering the next 5 years.* Under the regulation, DNSPs are to review the network management plan when any significant changes occur and in any event at least once every 2 years. (This management plan considers operational issues, some of which are outside the planning framework). Additional plans – Under the code of practice, DNSPs are to produce an "Electricity System Development Review" (ESDR), looking out over the "foreseeable future". (This requirement is included in the Draft Framework where an annual report on planning would be required.)	*Plan covering the next 5 years.* Under the code, DNSPs are required to produce plans on meeting forecasted demand requirements and improving reliability looking at the next five years in a Distribution System Planning Report (DSPR). (This requirement is included in the Draft Framework.)	*Plan covering the next 3 to 5 years.* ETSA is required to publish an Electricity System Development Plan (ESDP) setting out its planning criteria and five years of historical and forecast load data and expected network constraints over the next three years. (The forecasting requirement is included in the Draft Framework , which would extend the forward looking period to five years for system limitation data. The Draft Framework also requires a qualitative assessment of historical performance and compliance. It has been considered that as the planning reports are forward looking and historical information is reported under other requirements, it would not be included in the Draft Framework.)	*Plan covering the next 5 years.* Under the code, the DNSP is required to provide an annual plan on meeting predicted demand and improving reliability covering the next five years. (This requirement is included in the Draft Framework.)

[99] There are no state-based requirements for the ACT.

[100] Any applicable industry codes as outlined. Refer to Appendix B of the Scoping and Issues Paper for additional details on applicable Acts and Regulations and licence conditions.

Summary of the Current Distributor Planning Requirements (compared with the Draft Framework)[99]

	QLD	NSW	VIC	SA	TAS
Contents of plans	*Requirements are outlined in the code.* The Electricity Industry Code section 2.3.2 specifies that the network management plan is to include: • Background providing an explanation of the purpose of the report; (Included in Draft Framework .) • General information on the DNSP's supply network; (Included in Draft Framework .) • Forecasts and discussion of the current operating environment; (Included in Draft Framework .) • Asset management policy and qualitative assessment of its compliance with the policy; (Included in Draft Framework where a general summary of the asset management strategy is required and a qualitative assessment of the DSNP's compliance with its regulatory requirements.) • Demand management strategy including description of existing and planned programs and opportunities for demand side participation; (Included in Draft Framework .)	*Requirements are outlined in the regulation for the "management" plan and a specific guideline is issued by the Department of Energy, Utilities and Sustainability (DEUS) for the "performance" plan.* The Electricity Supply (Safety and Network Management) Regulation 2008, Part 3, sets out the required contents for the network management plan. These include discussion of: • Characters of the distribution network; (Included in Draft Framework.) • Planning process employed including demand management technologies; system reliability planning standards; (Included in Draft Framework.) • Asset management strategies including risk management; technical service standards for quality and reliability of supply; (Included in Draft Framework where summary information on these areas would be required.) • Safety management strategy including analysis of hazardous events;	*Requirements are outlined in the code.* The Electricity Distribution Code section 3.5 specifies that the distribution system planning report is to detail plans for the following 5 years covering areas including: • Forecast and historical demand; (Forecast demand included in Draft Framework. Description of performance of preceding year also required.) • Feasible options for meeting forecast demand including opportunities for embedded generation and demand management; (Included in Draft Framework.) • Preferred option for meeting forecast demand details including estimated costs; (Included in Draft Framework.) • Ability to defer or avoid augmentation by reducing forecast demand through embedded generation or demand management; (Included in Draft Framework.) • Impact of loss load assessment; (Not specifically included in the	*Requirements are outlined in an industry guideline.* The Electricity Industry Guideline No. 12 (made under section 8 of the Essential Services Commission Act 2002) sets out in detail the DNSP's obligations to report and consult on its system constraints and demand management plans. The guideline specifies that the ESDP is to include: • Background providing an explanation of the purpose of the report; (Included in Draft Framework.) • General information on the DNSP's supply network; (Included in Draft Framework.) • Descriptions of the basis for formulating load forecasts; (Included in Draft Framework.) • System planning and reliability guidelines; (Descriptions of the planning methodology and reliability standards are included in Draft Framework.) • Description of the state-wide sub-transmission network; (Description of the distribution network	Requirements are outlined in the code. The Tasmanian Electricity Code clause 8.3.2 specifies that an annual distribution system planning report detailing plans over the following five years is to include: • Forecast and historical demand; (Forecast demand included in Draft Framework. Description of performance of preceding year also required.) • Feasible options for meeting forecast demand including opportunities for embedded generation and demand management; (Forecast demand included in Draft Framework. Description of performance of preceding year required.) • Preferred option for meeting forecast demand details including estimated costs; (Forecast demand included in Draft Framework. Description of performance of preceding year required.) • Ability to defer or avoid augmentation by reducing forecast demand through embedded generation or demand management;

Summary of the Current Distributor Planning Requirements (compared with the Draft Framework)[99]

	QLD	NSW	VIC	SA	TAS
Contents of plans cont'	• Historical reliability performance for the previous five year period; (The Draft Framework requires a qualitative description of historical performance. More detailed historical information has not been required given the planning reports are forward looking.) • Statement of reliability targets for the next five years including details of improvement programs including major expenditure initiatives; (Included in Draft Framework.)and • Risk assessment of major constraints. (Included in Draft Framework.)	emergency procedures; adherence to safe working procedures; (Emergency procedures and adherence to safe working procedures would be an operational consideration and is not included in the Draft Framework . Consideration of contingency events should be included by DNSPs in their obligations under the Draft Framework to meet their reliability targets.) • Strategies employed to comply with licence conditions relating to the design and operation of the system. (Draft Framework requires a summary of the asset management strategy adopted.) The DEUS guideline sets out in detail the requirements of the annual network performance plan. The plan sets out the requirement to provide operational and planning statistics including in relation to: • Audits and independent appraisals conducted; (This is considered an operational issue and is not included in the Draft Framework.) • Network design planning	draft Framework however, DNSPs would be required to provide a description of the planning methodology employed and assumptions applied.) • Planning standards employed; (Included in Draft Framework.) • Reliability improvement programs description including the nature, timing, cost and expected impact on performance; (Included in Draft Framework as system limitations arising from the requirement to meet reliability standards are included.) • Reliability programs evaluation. (Not included as considered an operational requirement.)	included.) • Regional development plans; (Consideration of system limitations by asset level. No specific requirements for regional development have been included in the Draft Framework.) • Consultation Framework; (Included in Demand Side Engagement Strategy and under the RIT-D process.) • Register of interested parties. (Included in Draft Framework.)	(Forecast demand included in Draft Framework. Description of performance of preceding year required.) • Assessment of load at risk for the system and supply regions; (Not specifically included in the draft Framework however, DNSPs would be required to provide a description of the planning methodology employed and assumptions applied. Forecasts are also required to be provided at the system level taking into consideration peak conditions.) • Planning standards employed; (Included in Draft Framework.) • Reliability improvement programs description including the nature, timing, cost and expected impact on performance; (Included in Draft Framework as system limitations arising from the requirement to meet reliability standards are included.) • Reliability programs evaluation. (Not included as considered an operational requirement.)

Summary of the Current Distributor Planning Requirements (compared with the Draft Framework)[99]

	QLD	NSW	VIC	SA	TAS
Contents of plans cont'		criteria; (Draft Framework requires a description of the planning methodology adopted and the assumptions applied to planning and forecasting.) • Technical service standards; (Draft Framework requires a summary description of the reliability and quality of supply standards that apply.) • Detailed annual performance results; (Draft Framework requires a description of the performance of the preceding year.) • Network safety incidents and incident reports; (This is considered an operational issue and not included in the Draft Framework) • Customer installations. (Draft Framework s includes the requirement for DNSPs to forecast the level of embedded generation.)			

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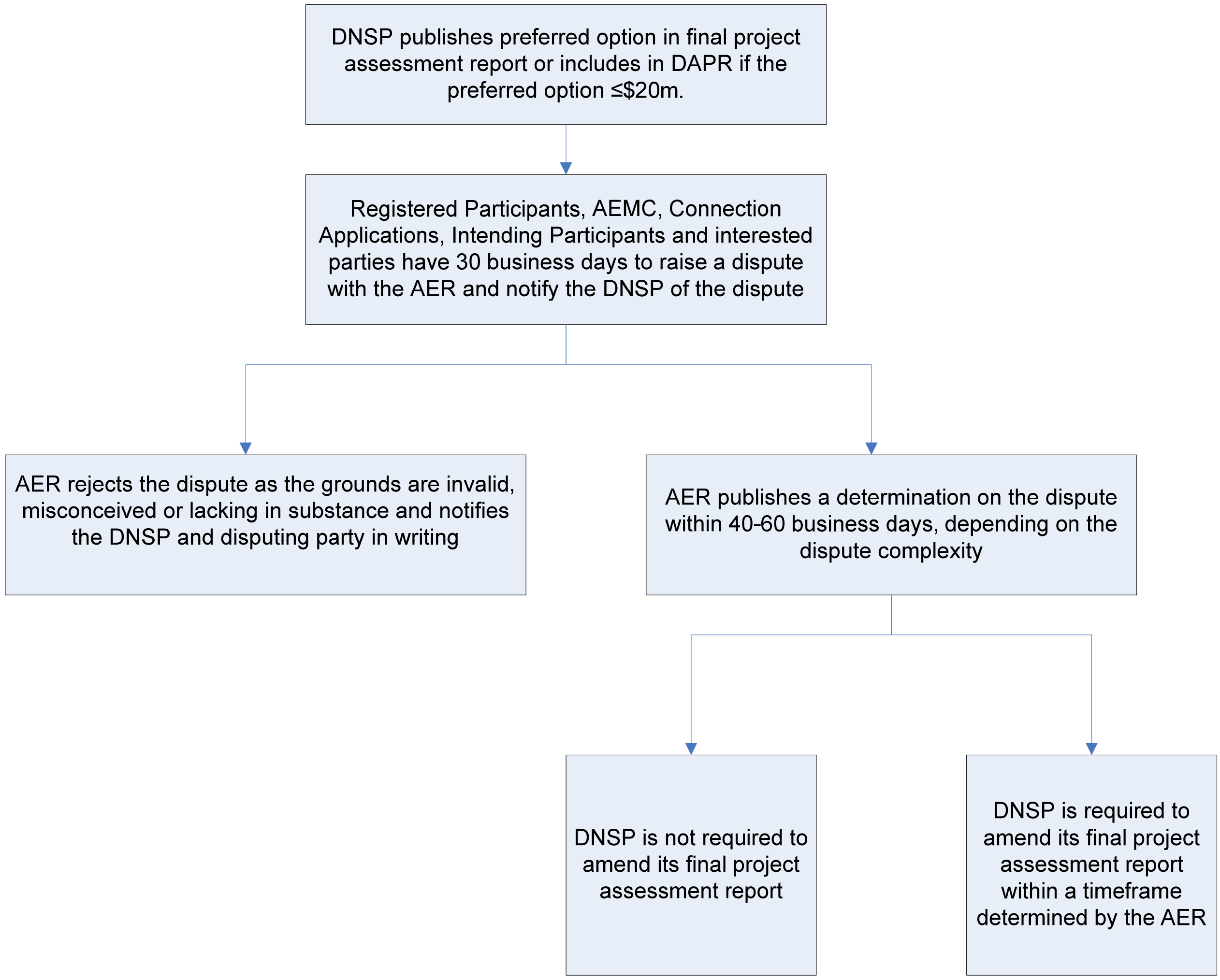
E Design of the Regulatory Investment Test for Distribution and Dispute Resolution Process

Diagram 1: Design of the RIT-D

Exempt from RIT-D	Most expensive investment option is below $2m	OR the investment is exempt from the RIT-D as it is: urgent and unforseen; a negotiated service; an unclassified service; an alternative control service; a customer asset which will not be part of the shared network; a jointly planned investment; or a replacement or refurbishment, where the augmentation component is below $2m.				Preferred option is published in DAPR
Identified need does not meet STT and preferred option <$10m	DNSP undertakes Specification Threshold Test (STT)	Identified need does not meet STT. DNSP publishes STT report.	DNSP undertakes project assessment process	Preferred option is < $10m		DNSP publishes preferred option in final project assessment report or includes in DAPR
Identified need does not meet STT and preferred option ≥$10m	DNSP undertakes Specification Threshold Test (STT)	Identified need does not meet STT. DNSP publishes STT report.	DNSP undertakes project assessment process	Preferred option is ≥ $10m	DNSP publishes preferred option in draft project assessment report and consults on report for 30 business days	DNSP publishes preferred option in final project assessment report or includes in DAPR if preferred option ≤$20 m
Identified need meets STT but DNSP has not undertaken prior non-network engagement	DNSP undertakes Specification Threshold Test (STT)	Identified need meets the STT.	DNSP publishes project specification report. Consultation is 6 months as DNSP has not undertaken prior non-network engagement.	DNSP undertakes project assessment process	DNSP publishes preferred option in draft project assessment report and consults on report for 30 business days	DNSP publishes preferred option in final project assessment report or includes in DAPR if preferred option ≤$20 m
Identified need meets STT & DNSP has undertaken prior non-network engagement	DNSP undertakes Specification Threshold Test (STT)	Identified need meets the STT.	DNSP publishes project specification report. Consultation is 1 month as DNSP has undertaken prior non-network engagement.	DNSP undertakes project assessment process	DNSP publishes preferred option in draft project assessment report and consults on report for 30 business days	DNSP publishes preferred option in final project assessment report or includes in DAPR if preferred option ≤$20 m

Diagram 2: Design of the Dispute Resolution Process



F Distribution Reliability in the NEM

The reliability of distribution systems in the NEM varies significantly across different geographic areas. Reliability is generally best in CBDs and high density inner urban areas (typically 2 – 20 minutes off supply per annum), and worst in remote rural areas where outages may exceed 1000 minutes in aggregate per annum.

The reliability of distribution systems vary significantly. The exact reasons for the differences have not been studied, however some of the factors that influence differences in reliability performance are discussed in this Appendix.

Distribution reliability in Australia is measured using three parameters, namely SAIDI, SAIFI and CAIDI, which are defined below:

System Annual Interruption Duration Index (SAIDI) is the sum of the duration of each sustained customer interruption, multiplied by the number of customers impacted by each interruption, divided by the total number of customer's serviced (expressed in minutes).

In common language, SAIDI is the average aggregate number of minutes per annum that supply is lost (for greater than one minute), to the average customer.

System Annual Interruption Frequency Index (SAIFI) is the total number of sustained customer interruptions, multiplied by the number of customers impacted by each interruption divided by the total number of customers serviced (expressed as a unit number).

In common language, SAIFI is the average number of outages that the typical customer will experience in a year.

Customer Average Interruption Duration Index (CAIDI) $= \dfrac{SAIDI}{SAIFI}$

In common language, CAIDI represents the average time taken to restore supply, after an interruption occurs.

F.1 Factors Effecting the Reliability of Distribution Systems

F.1.1 Legacy Issues and Externalities

DNSPs in Australia are faced with managing and improving the reliability of their distribution systems under circumstances where historical decisions taken many years ago have left them with a legacy of system design and configuration issues, which cannot be easily changed in the short to medium term.

In addition, the performance of any distribution system is affected by local environmental, weather and terrain factors for which the design of the distribution system can mitigate against, but cannot eliminate (e.g. bushfires, earthquakes, cyclones, etc.).

F.1.2 System Security

Most distribution systems worldwide are designed and operated with their distribution and sub-transmission systems being partly radial (no redundancy) and partly meshed (N-1 redundancy or better). There are many variations in the practices of designing redundancy into a distribution/sub-transmission system, including load management, embedded generation, manual switching, automated switching, etc., but the fundamental issue that most impacts the level of reliability achieved is whether the system is radial, or whether it has in-built redundancy (full or partial) to cater for an N-1 contingency.

The system security standards used by DNSPs in the NEM are summarised in Appendix A of the SKM Background Report.

Distribution/sub-transmission networks are complex systems, with many different components (transformers, overhead feeders, underground feeders, switches, etc.), each with their own individual failure modes, failure rates and mean repair times. To be able to accurately statistically model the impact of the different levels of system security on the level of reliability achieved by distribution companies requires large amounts of data and complex modelling techniques (e.g. Markov modelling).

F.1.3 System Configuration & Design Factors

The reliability of a distribution network is intrinsically dependent on the network configuration/design characteristics, the environment in which it operates in, and the maintenance practices employed. Factors such as customer density, operating environment, and geographic service area, influence the design of the distribution system, as do economic and safety considerations.

Examples of differences that exist between various parts of the distribution systems used in Australia include:

- Customer/load density;
- Voltage levels;
- Network length and service area;
- Mix of overhead and underground;
- Backup/duplication for network failures (planning philosophies) and the degree of spare tie capacity (asset utilisation);
- Automatic protection schemes to remove faults and limit the number of customers interrupted; and
- Remote control load transfer schemes to improve the speed of restoration for faults.

At one extreme is a fully underground meshed network for a CBD type network, which may deliver around 2 – 10 minutes of SAIDI, and at the other extreme is a fully overhead radial network for short and long rural networks ,which may deliver 200 – 600 minutes of SAIDI or more. Most Australian DNSPs operate a mixed underground and overhead network. The majority of urban customers are supplied from a mixed overhead / underground interconnected network, while most rural customers are supplied from an overhead radial network.

F.1.4 Environmental Factors

Australia is a large and diverse country with significant extremes in the terrain, environmental and weather conditions that impact on the operation of the distribution systems. Those environmental factors that most impact on the reliability performance of distribution systems include:

- Vegetation density;
- Bird and wildlife activity;
- Human activity;
- Storm activity (both electrical and wind);
- Heavy rain and flooding;
- Temperature extremes; and
- Remoteness.

These influencing factors vary in their relative impact on different parts of the distribution systems. For example, storm activity tends to have a greater impact on the overhead system, whereas heavy rain and flooding tends to have greater impact on underground systems and ground level equipment.

The differences in performance across apparently similar systems can be quite dramatic. For example, it is well recorded that across a wide range of overhead distribution systems (11 kV / 22 kV), both in Australia and overseas, the average annual fault rate in overhead distribution systems is about 10 sustained outages per 100 km of line, per annum. What is not so well known is that the single wire, earth return (SWER) systems supplying the remote parts of rural Australia actually exhibit lower than average fault rates (possibly as low as 2 – 5 outages/100 km/annum), while overhead feeders in urban areas exhibit higher than average fault rates, some as high as 30 – 40 outages/100 km/annum.[101]

The reasons for these differences are explained by the fact that:

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[101] SKM fault rate and reliability database.

- SWER systems are of a simple design, with fewer components to fail;
- Distribution lines in urban areas are more complex, with more poles, more insulators, more components generally to fail;
- Vegetation and wildlife (possums, etc.), generally has closer access to overhead lines in urban areas, with trees growing close to houses, service wires and street mains; and
- Human activities in urban areas have a greater impact on overhead distribution (e.g. cars hitting poles, high vehicle transport, other construction activities, etc.).

Although fault rates (expressed as faults/100 km/annum), are higher in urban areas than rural areas and the number of customers impacted in urban areas are generally higher, the overall SAIDI minutes of supply are higher in rural areas due to the longer lengths of overhead lines and longer response times.

F.1.5 Other Factors

Other important factors that can have an impact on the overall level of distribution system reliability include:

- The ageing and deterioration of the condition of critical infrastructure assets;
- Asset management philosophy and general maintenance policies and practices;
- Fault levels and equipment / feeder loadings;
- The extent to which live line work practices are adopted;
- Auto-reclose and remote reclose practices; and
- Extent of Supervisory Control and Data Acquisition (SCADA) and distribution automation (DA or Smart Networks).

F.2 Differences in the Underlying Performance Potential of Different Distribution Systems

As noted in the previous section, there are a range of factors which can influence the reliability performance of a distribution system. Some of these factors are within the ability of DNSPs to control, or at a minimum, influence, while other factors are of a legacy nature beyond the immediate ability of the DNSP to mitigate against. Some of these legacy and external influences are discussed below.

F.2.1 Selection of Primary Distribution Voltage

Historically, and for a variety of reasons, the primary distribution systems in Australia are built and energised at different voltages, the most common being 11 kV and 22 kV. There are also small amounts of other legacy voltages such as 5 kV, 6.6

kV, etc. In addition, many parts of rural and remote rural areas are supplied by 12.7 kV and 19.1 kV SWER systems.

Approximately 70 – 80% of all customer minutes lost (SAIDI) occur on the primary distribution systems, and consequently the number of customers connected, the exposed length of overhead line, and the outage performance (outages/100 km/annum) is critical in determining the overall reliability of a DNSPs network.

The main difference in the relative performance between 11 kV systems and 22 kV systems comes from the first two of these factors, namely:

- The difference in the average number of customers connected per 11 kV and 22 kV feeder; and
- The difference in the route length of exposed overhead line per 11 kV and 22 kV feeder.

While there may also be differences between the fault rates (per 100 km/annum) on 11 kV lines versus 22 kV lines, there are no known national or international studies to confirm this, and most studies assume a similar outage rate.

As indicated above, it is known that the average number of customers connected to each 22 kV feeder in Australia is significantly higher than the average number of customers connected to each 11 kV feeder. While the exact number will vary from network to network (and will depend predominantly on whether they are CBD, urban, rural or remote rural feeders) typically one would expect to find between 3000 – 5000 customers connected to a 22 kV feeder in an urban area, while typically only 1000 – 2000 customers may be connected to an 11 kV feeder in a similar urban area.

This means that for every substantial fault on the 22 kV feeder, and assuming a similar network configuration and level of automation, more customers lose supply on a 22 kV feeder than an equivalent 11 kV feeder resulting in proportionately higher SAIFI and SAIDI.

Similarly, one of the reasons that 22 kV was historically favoured over 11 kV is that it can convey electrical loading over longer distances than 11 kV, without suffering from excessive voltage drop. It is often favoured therefore, for supplying rural areas, resulting in more customers being connected per feeder and the feeder having a greater level of exposed route length.

In a study of selected Australian and international utilities conducted by SKM, it was found that this difference in the selection of primary distribution voltage (and the subsequent impact on customers connected and exposed route length) was the single largest factor in explaining differences in system reliability (SAIDI).

F.2.2 Mix of Overhead and Underground Systems

Appendix B of SKM's Report to the AEMC identified the different levels of undergrounding that exists between DNSPs in Australia. This is summarised in Table F.1 below, together with the primary distribution system voltage level.

Table F.1: Comparison of overhead and underground systems between Australian DNSPs[102]

DNSP	Distribution voltage (kV)	% underground (approx.)	% overhead (approx.)
ETSA Utilities	11	17	83
CitiPower	11 & 22	37	63
Powercor	22	5	95
Jemena	22	Not available	Not available
SP AusNet	22	0.5	99.5
United Energy	22	Not available	Not available
Aurora	11 & 22	8	92
EnergyAustralia	11	28	72
Integral Energy	11	31	69
Country Energy	22	3	97
ActewAGL	11	54	46
ENERGEX	11	28.8	71.3
Ergon Energy	11 & 22	3.5	96.5

Note:
Dominant primary distribution voltage shown first.
SWER and other minor voltages not listed.

As can be seen, the level of undergrounding varies from a minimum of 0.5% (SP AusNet) to a maximum of 54% (ActewAGL).[103]

Since the average fault rate (outages/100 km/annum) on an overhead system is approximately three times that on an underground system (approximately 10.2 compared with 3.5), this will be a significant factor in overall system reliability (SAIDI).[104]

F.2.3 Weather Influences

The exclusion of extreme weather and other events such as cyclones, bushfires, etc. using the 2.5 beta method (or any other method), generally does not compensate for differences in the ongoing daily, weekly and annual variations in weather patterns from country to country, state to state, or region to region. The differences in the levels of “average thunder days”, “heavy rain days” and “high wind days”, can

102 Ibid.

103 SKM, 2009, ‘Advice on Development of a National Framework for Electricity Distribution Network Planning and Expansion’, Appendix B, 13 May, 2009.

104 SKM reliability and fault rate database.

impact on distribution systems in different ways, and can be significantly different from region to region, as shown in the following table.

Table F.2: Relativity of weather events[105]

Weather event per annum	Queensland	Victoria	New Zealand
Average thunder days	20 – 40 (11%)	10 – 20 (6%)	10 – 15 (4%)
Heavy rain days (>50 mm)	7.5	1	5
Percentage high wind (>30 km/hr)	3%	21%	0.6%

In the SKM study of selected national and international utilities, the relative impact of prevailing weather conditions was second only to the selection of primary distribution voltage levels in explaining differences in the reliability of distribution factors, of those factors that were outside of the immediate control of distribution companies.

F.3 Other Influencing Factors

This appendix has described the relative impact that external or unmanageable factors (at least in the short term) have on the overall reliability of distribution systems. In addition, there are a number of other factors that are within the control and decision making processes of a DNSP to influence. The most notable of these and those which have most impact on overall system reliability are:

- Geographic area and travel times;
- Live line work practices;
- Extent of SCADA and distribution automation; and
- Auto reclose and remote reclose practices.

[105] Bureau of meteorological data for the jurisdictions indicated for 2005.