AEMC

REVIEW

Australian Energy Market Commission

FINAL REPORT

Review of National Framework for Electricity Distribution Network Planning and Expansion

Commissioners

Tamblyn
Ryan
Woodward

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Inquiries

The Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

E: aemc@aemc.gov.au
T: (02) 8296 7800
F: (02) 8296 7899

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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
DPI	Department of Primary Industries, Victoria
Draft Report	AEMC 2009, *Review of National Framework for Electricity Distribution Network Planning and Expansion*, Draft Report, 7 July 2009, Sydney
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 Final Report sets out our recommendations and supporting reasoning for the design of the national framework. Submitted with our Final Report are also draft amendments to the National Electricity Rules (Rules), which are reflective of our recommendations.

Our 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 distribution network service providers' (DNSPs) planning and investment activities would be provided to allow market participants to make efficient investment decisions and to enable non-network providers to raise credible alternatives.

We have developed our recommendations having regard to the National Electricity Objective and to achieve a set of principles, which include economic efficiency, transparency, proportionality, technology neutrality and consistency across the National Electricity Market (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, meetings and a public forum.

The planning arrangements for the national framework consist of the annual reporting process, the Demand Side Engagement Strategy and the Regulatory Investment Test for Distribution (RIT-D) process. It is through the interaction of these three components that the intended purpose and objectives of the national framework is best achieved. The effective utilisation of the proposed 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.

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 of planning to be fully realised. This would include planning activities associated with replacement assets and the provision of 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 Demand Side Engagement Register. This strategy recognises the importance of proactive engagement by both DNSPs and non-network providers 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, and promotes a constructive working relationship between the distribution businesses and non-network providers. The strategy would work together with the Distribution Annual Planning Report and RIT-D 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. The DAPR would need to be certified by the Chief Executive Officer and a Director or Company Secretary and each DNSP would be required to conduct a public forum on its DAPR (within three months) if requested to do so by a stakeholder.

For the DAPR, the DNSPs would be required to report on capacity and load forecasts (including peak demand) for sub transmission assets, zone substations and transmission-distribution connection points. The DAPR would also set out information for any primary distribution feeders which were overloaded (or forecast to be overloaded within the next two years), where they have been identified by the DNSP. The DNSPs would also be required to explain any aspects of the forecasts and modelling that have changed significantly from the previous year's report.

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 capacity constraints. The DAPRs would include detailed information on system limitations, including: the location and estimated timing of the system limitations; analysis of potential load transfer capability; the impact on transmission connection points; and potential solutions that may address the limitation. The DAPR would also contain regional development plans. Such plans increase transparency and provide useful information to regional communities about the DNSP's planning, load forecasts and expected network constraints.

DNSPs would also be required to report on their planning methodologies; outcomes from joint planning with transmission network service providers (TNSPs) and other DNSPs, and provide a summary explanation of their asset management practices, performance standards and compliance against those standards. In addition, we also recommend that the DNSPs be required to inform on their activities and actions taken to promote non-network initiatives, including embedded generation, and on any significant investments in metering services. As distribution businesses become more 'active' and employ smart grid technologies to manage flows and constraints more efficiently, it is important that the DAPR informs stakeholders on these developments.

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, which is consistent with the current requirements for joint planning under the Rules.

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). This includes any network-to-network connection investment proposals. 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 (RIT-D)

We propose that a new project assessment process – the 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 investment option that maximises the present value of net economic benefit to all those who distribute electricity in the market (the preferred option). 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 to address a regulatory performance standard requirement. 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 market benefits which can be achieved through distribution investments are also 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 $5 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. This threshold would also be aligned with the current threshold for RIT-T and would reduce the regulatory burden on DNSPs as well as the Australian Energy Regulator (AER). Non-network providers would be able to investigate and propose alternative investment options through the Demand Side Engagement Strategy for all projects including those that fall below this threshold.

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

Specification Threshold Test (STT)

An initial screening test, the Specification Threshold Test (STT), would be applied to all investments which are subject to the RIT-D. This test determines the scope of projects which would be subject to consultation on possible alternatives prior to the project assessment stage. Investments which do not meet the requirements of the STT would be subject to a 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 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. We recommend that primary distribution feeders investment be within the scope of the RIT-D.

Project Specification Stage

The purpose of the project specification stage under the RIT-D is to require DNSPs publicly to 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 consultation stage of the RIT-D.

Dispute Resolution

The purpose of the dispute resolution process for the national framework is to provide an accessible and timely mechanism for Registered Participants, the AEMC, AEMO, Connection Applicants, Intending Participants, interest parties and non-network providers to question DNSPs' decision making, and in doing so, provide transparency to DNSPs' decisions and regulatory monitoring of their behaviour. The AER would run the dispute resolution process.

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 regarding 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 Registered Participants, the AEMC, the AEMO, Connection Applicants, Intending Participants, interested parties and non-network providers should be able to raise disputes regarding 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. These activities relate to forecasts of future scenarios rather than commitments to undertake particular actions or investments.

AEMC Review

We recommend that the AEMC be required to review the operation of the national framework after three years of it coming into effect. The purpose of this review would be to assess the effectiveness of the provisions against the MCE objectives and to identify any potential areas for further improvement.

Implementation

The national framework is not intended to result in the duplication of planning arrangements. Our recommendations assume that the existing jurisdictional arrangements for project assessment, and annual planning and reporting, to the extent that they are covered by the national framework, would be rolled back once the national framework is in place.

We anticipate that each jurisdiction would review its planning provisions to determine how to, and the timing of, transition to the national framework, plus whether there would be any specific jurisdictional requirements that should be retained (i.e. any specific jurisdictional requirements not covered by the requirements of the national framework). The annual planning process and reporting requirements, as reflected in the draft Rules, provide flexibility for jurisdictions to include additional reporting and planning requirements.

The introduction of the national framework may result in significant changes to DNSPs' and other market participants' operational practices. It would also require the AER to develop a new RIT-D and supporting guidelines. Given this, we propose that a one year transition period should apply before the RIT-D commences, after any Rule changes have been made. Regarding the annual planning process and reporting requirements, we consider that DNSPs would need at a minimum nine months before the publication date of the first DAPR to comply with the new requirements. Co-ordination between the Rule making process and amendments to jurisdictional instruments will be needed.

Suggested Review into Distribution Reliability Standards

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

The security of supply and reliability standards, set out in jurisdictional instruments, underpin how the network planning, investment and operation processes are currently undertaken by the DNSPs. We consider that divergent arrangements and processes in the setting of reliability standards may affect the achievement of the desired objectives for the national framework. Given this, we suggest that a separate review is initiated by the MCE into the security and reliability standards relating to the design and planning of distribution networks.

There is a lack of consistency and transparency in how the different jurisdictional standards are determined and described. Also how the distribution businesses interpret and comply with these standards can vary significantly across the NEM.

These factors can undermine market participants' understanding of, and expectations regarding, network reliability and security performance, reducing their capacity to make efficient location decisions.

These variations also make it difficult for non-network providers to operate on a NEM wide basis as they have to be familiar with the different methods used to express, deliver and report reliability standards. Furthermore, if the form of standard is not economically derived (such that they would consider customer value of reliability), efficient provision of reliability may not occur and the prospects for the inclusion of demand side participation are diminished.

This review of security and reliability standards would assess whether national consistency in these arrangements could:

- deliver net benefits to the market in the form of efficient provision of reliability by promoting more efficient and timely network investment, and improving network operation and performance;

- strengthen the accountability of DNSPs for cost-effective achievement of the reliability and security standards; and

- improve the transparency of network reliability and security performance to users of network services, providers of non-network alternatives and final energy consumers.

We have provided a draft terms of reference for the MCE's consideration in this Final Report. We do not consider that harmonisation of the existing jurisdictional security and reliability obligations is appropriate. As the performance of networks, and its applicable standards, is directly attributable to the network characteristics and the resources which are invested, it is appropriate for the standards to differ across jurisdictions. The objective of this review is to assess whether there would benefits from developing national consistency in the methods for describing and applying the differing standards.

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1 Introduction

The Ministerial Council on 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 such planning and expansion (the Review).

This Final Report sets out our recommendations for the national framework. It discusses the various components of the national framework and provides the supporting reasoning behind our recommendations. Accompanying this final report is a draft Rule change request with proposed Rules to implement the design for the national framework recommended in this Final Report.

This Chapter describes the MCE's terms of reference for the Review and discusses the context of, and the approach taken to, the Review. It also sets out a series of design principles, consistent with the National Electricity Objective (NEO), against which we have tested our recommendations. Finally, the Chapter discusses the implementation issues for the national framework and recommends that a review on the effectiveness of the national framework be conducted after three years of operation.

1.1 The Review Framework

The regulatory arrangements governing distribution network planning are contained in Chapter 5 of the Rules and also in various jurisdictional instruments. These two regimes do not operate in a complementary way and, as a result, the obligations of Distribution Network Service Providers (DNSPs) for network planning are 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 associated with 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.

1.2 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.[1] The MCE's 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;

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

- 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 provides 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 electricity supply;
- 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 is made transparent 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 connections 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;
- a level playing field is ensured for all regions in terms of attracting investment and promoting more efficient decisions; and
- the regulatory compliance burden is reduced for participants operating in more than one region in the National Electricity Market (NEM).

1.3 Context for Distribution Planning

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.[2] Within that it is the radial and meshed networks of the medium voltage primary distribution systems (typically 11 kV and 22 kV) that contribute about 75% of all minutes off supply to

2 Australian Energy Regulator, State of the Energy Market 2008, November 2008, p. 156.

electricity customers.[3] The DNSPs' planning decisions are mostly directed towards meeting their prescribed reliability standards.

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 jurisdictional level.

Table 1: Framework for Distribution Planning in the NEM

Planning Requirement	Jurisdictional Obligation	National Obligation
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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

3 Supporting background material on factors which influence the reliability and quality of supply plus a comparison of the NEM performance against 11 overseas counties in Appendix F.

Reliability Standards

The security of supply and reliability standards, which are set out in jurisdictional instruments and Schedule 5.1 of the Rules 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 that a mixture of deterministic and probabilistic criteria are currently being applied.[4] It is noted that the form, function and processes for setting the criteria, in addition to how a DNSP interprets and complies with the criteria, vary significantly across the NEM.

It is appropriate that 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 providers 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.

Given the importance of the role of security and reliability standards in distribution planning, we suggest that a further review is undertaken to assess whether there are aspects of the current processes and frameworks on how standards are determined and operated that would benefit from being consistently applied across the NEM. Any such review would recognise the need for jurisdictional standards to differ to reflect different physical characteristics of the networks and the existing regulatory treatments in balancing reliability and costs to consumers. The scope of the suggested review is discussed in Chapter 6 and a draft terms of reference for the MCE's consideration is provided in Appendix B.

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 Rules. These arrangements have a significant influence on 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.[5]

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

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

Future reforms in distribution planning

The arrangements governing and affecting investment in, and the operation of, electricity distribution networks are undergoing 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 (NSPs). Also, electricity distribution systems are evolving towards becoming "active networks" that interact with both demand and supply sides. Industrial combined heat and power, distributed 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 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 have managed the various interactions between this Review and other work-streams as we conducted 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 which aspects of the current jurisdictional requirements should be maintained and which 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. These workshops provided interested parties with an opportunity to comment on a proposed "high level" design and contribute to the development of the proposed 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 the AEMC website at: www.aemc.gov.au.

Prior to the workshops, we published the SKM Background Report.[6] 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.

On 7 July 2009, we published the Draft Report for the Review. The Draft Report set out our draft recommendations and supporting reasoning for the design of the national framework. It also included draft specifications for the national framework, which set out in detail our draft recommendations.

A public forum on the Draft Report was held on 5 August 2009, during which we presented our draft recommendations and gave stakeholders an opportunity to ask questions and comment on any issues prior to finalising their written submissions. Submissions on the Draft Report closed on 13 August 2009, with 19 submissions received. Comments raised at the public forum and the submissions received on the Draft Report were considered in the development of this Final Report and accompanying draft Rules. The Final Report considers the key issues. Our response to detailed comments raised by stakeholders on the Draft Report are set out in Appendix A.

1.4.2 Principles for the Review

In developing our recommendations for a national framework for distribution network planning, we were 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.[7]

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 and Draft Report.

6 SKM Background Report, op. cit.

7 Section 7, National Electricity Law.

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 processes 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. **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 jurisdictional 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 Final Report

The remainder of the Final Report contains the 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 – Review into Distribution Reliability Standards and other issues
- Appendix A – Responses to Issues Raised in Submissions on the Draft Report
- Appendix B – Proposed Terms of Reference for the Distribution Reliability Standards Review
- Appendix C – Related AEMC Reviews and Rule changes
- Appendix D – Comparison of Jurisdictional Reporting with the National Framework
- Appendix E – RIT-D and Dispute Resolution Process Flowcharts and comparison with RIT-T
- Appendix F – Distribution Reliability in the NEM
- Appendix G – Joint Planning in Victoria

1.6 Implementation of the National Framework

The MCE will consider the recommendations in the Final Report and the draft Rules and decide upon the appropriate design for the national framework. The national framework would then be implemented through a Rule change process initiated by the MCE and amendments to the existing jurisdictional arrangements.[8]

The national framework is neither intended to result in the duplication of planning arrangements, nor is it being designed to work in parallel with the current jurisdictional requirements. Our recommendations rest on the assumption that existing jurisdictional arrangements for project assessment and annual planning and reporting, to the extent that they are covered by the national framework, will be rolled back once the national framework is in place. Transitional provisions will be needed as the national framework is implemented.

As a part of the transition process, we anticipate that each jurisdiction would review its planning provisions to determine whether there would be any specific, additional jurisdictional requirements that should be retained. The annual planning process and reporting requirements, as reflected in the draft Rules, provide flexibility for jurisdictions to include additional reporting and planning requirements. The introduction of the national framework may result in significant changes to DNSPs' and other market participants' operational practices and appropriate time should be permitted for the transition to the new arrangements.

Regarding the annual planning process and reporting requirements, we consider that DNSPs would need at a minimum nine months before the publication date of the

8 The appropriate application of civil penalties provisions will be addressed under the Rule change process.

first Distribution Annual Planning Report (DAPR) to comply with the new requirements. In addition, requirements for jurisdictional reporting would also need to be clarified to ensure there is no duplication of reporting 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.

The Victorian distribution businesses disagree with a 2010 start date, arguing that it would not be suitable to introduce the new arrangements until the commencement of their next regulatory period (on 1 January 2011). While the timing will be a matter for the MCE, we advise that the framework is introduced as soon as practicable.

Specific transitional arrangements for jurisdictions to adapt to the national framework may also be required. We consider that a detailed implementation plan will need to be developed for the transition to the national framework and to co-ordinate the Rule change and the amendments to the jurisdictional requirements. It is appropriate for such a plan to be developed, and agreed to by the jurisdictions, as part of the MCE's response to this Final Report.

The proposed arrangements will 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.

1.7 Components of the National Framework

The planning arrangements for the national framework consist of the annual reporting process, the Demand Side Engagement Strategy and the RIT-D process. 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. Therefore it would not be appropriate for the various components of the national framework to be implemented in different stages.

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.[9]

[9] See, for example, ActewAGL's submission to the Scoping and Issues Paper.

1.7.1 Proposed Future Review of the National Framework

The effectiveness of each of the components under the national framework would likely improve over time as DNSPs and stakeholders adjust to the requirements and learn to utilise the information and processes available. For this reason, we recommend that the AEMC be required to conduct a review of the national framework three years after it comes into effect. The purpose of this review would be to assess the effectiveness of the provisions and to identify any potential areas for further improvement.[10]

10 To account for the fact that the provisions may come into effect in each jurisdiction at a different time, the draft Rules provide that the AEMC will conduct a review no earlier than three years but no later than five years after the Rules come into effect.

2 Annual Planning Process

This Chapter sets out the recommendations on the national annual planning process for distribution. It describes the proposed annual planning process, including the proposed Demand Side Engagement Strategy, which is a new obligation aimed at providing transparency on how DNSPs assess and consider non-network alternatives, and promoting a process for DNSPs to engage with non-network providers. Requirements for the joint planning activities undertaken by Transmission Network Service Providers (TNSPs) and DNSPs are also discussed.

Summary of 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 engage with non-network providers 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 if requested to do so by a Registered Participant, Connection Applicant, Intending Participant or a stakeholder registered on its Demand Side Engagement Register.[11]

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. This includes any proposed transmission-distribution connection investments.

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 timely manner. A national annual planning process ensures that all DNSPs conduct a clearly defined, common and efficient planning process.

11 The draft recommendation required a mandatory public forum to be conducted. The final recommendation has been amended giving consideration to comments received from stakeholders. In addition, the "Demand Side Engagement Register" replaces the "Register of Interested Parties" discussed in the Draft Report.

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

2.2 Addressing the Principles for the Review

In developing our recommendations for the annual planning process in this Chapter, we have taken into consideration the following principles.

Economic Efficiency:

Consistent with the economic efficiency principle, the annual planning process would require:

- DNSPs to consider all feasible options for network development, including allowing potential non-network providers to engage with the development process through the Demand Side Engagement Strategy; and

- investments identified through the joint planning process to be subject to one regulatory investment test, which would ensure that the optimal overall solution would be identified.

Transparency:

The recommendations for the annual planning process achieve the principle of transparency:

- the Demand Side Engagement Strategy would require DNSPs to set out the processes that they follow in assessing non-network options and engaging with non-network providers. The requirements under this strategy would provide greater certainty to potential investors and non-network providers; and

- the requirements for DNSPs and TNSPs to carry out joint planning would be clarified to require the parties to meet on a regular and as required basis and inform on joint planning activities.

Proportionality:

Consistent with the principle of proportionality, the recommendations provide for a national framework that:

- allows DNSPs to prepare forecasts to the best of their ability without prescription on how DNSPs should model the future and determine such forecasts;

- provides for a Demand Side Engagement Strategy which allows DNSPs to develop their existing business processes and promote discussions between DNSPs and non-network providers in an efficient manner;

- provides for a database of case studies under the Demand Side Engagement Strategy where the DNSPs may determine the appropriate content based on their expertise and interaction with their stakeholders; and

- allows DNSPs to minimise the cost of publishing the annual planning reports by allowing the reports to be published on their own websites so that they may retain ownership of the publications without the requirement to provide the report to a third party for publication.

Technological Neutrality:

The recommendations require DNSPs to take into account the level of embedded generation in their planning and forecasting processes, and to establish and implement a Demand Side Engagement Strategy are consistent with the principle of technological neutrality.

Consistency across the NEM:

To provide that the framework enables a level playing field for all regions in terms of attracting investment and promoting more efficient decisions, the recommendations:

- require the establishment of a Demand Side Engagement Strategy, which will clarify the opportunities and processes for dealing with non-network alternatives in each jurisdiction; and

- provide for a consistent reporting arrangement across the NEM.

Fit for Purpose, Reflecting Local Conditions:

To recognise the differences in the planning methodologies and the relative importance of each asset and service class, the recommendations provide for flexibility to allow any specific jurisdictional and geographical requirements 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.

Building on Existing Jurisdictional Requirements:

The recommendations were developed giving consideration to the existing jurisdictional requirements for planning and reporting to ensure the integrity of the current provisions are maintained.

Consistency with Transmission Planning Framework

The recommendations require DNSPs to conduct joint planning and publish an annual planning report. This is consistent with the provisions under the transmission planning framework.

2.3 Scope and Requirements of the Annual Planning Process

Recommendation

The annual planning process would require DNSPs to carry out an annual planning process covering a minimum forward planning period of five years for assets in their distribution networks (and 10 years for any transmission assets operated by the businesses).[12]

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 network 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 their 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 their asset management policies.

Reasoning for 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 by the DNSP, 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 recommendations state that a minimum five year planning horizon would apply for distribution assets. To 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.

[12] For the avoidance of doubt, distribution assets include sub-transmission assets.

2.4 Demand Side Engagement Strategy

Recommendation

DNSPs would be required to engage with non-network providers 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. Demand Side Engagement Register.[13]

Reasoning for recommendation

The Demand Side Engagement Strategy recognises the importance of the proactive engagement of both DNSPs and non-network providers in developing potential solutions. Stakeholders have noted that currently it can be difficult for non-network providers 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 providers, providing improved opportunities for non-network providers 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 providers.

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 influenced by other regulatory and commercial drivers. The planning framework needs to operate with, and compliment, the other drivers that currently exist.[14]

In submissions on the Draft Report, some DNSPs submitted that the draft recommendations for annual planning were inconsistent with the draft findings from Stage 2 of the AEMC's Demand Side Participation (DSP) Review.[15] The submissions

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[13] As noted previously, the "Demand Side Engagement Register" replaces the "Register of Interested Parties" referred to in the Draft Report and Workshop Paper.

[14] In its submission on the Draft Report, the Victorian Department of Primary Industries (pp. 1-2) submitted that the full range of embedded generation projects were not captured by the review. It noted that many embedded generation projects are not driven by network issues but rather building owner/developers' incentives to improve value and increase greenhouse gas emissions. We note that one of the key purpose of the Demand Side Engagement Strategy would be to facilitate further engagement of non-network providers with DNSPs in these situations.

[15] See, for example, Jemena's submission on the Draft Report, p. 3.

referred to the draft findings from the DSP Review that a "network business that is regulated under a price cap has *private* incentives for buying DSP that are consistent with *socially* efficient levels of DSP".[16] For this reason, the DNSPs submitted that the recommendations under this Review outlining a prescriptive process for engagement of non-network providers is not consistent.

We note that the draft findings under the DSP Review relate to DNSPs' incentives to seek non-network alternatives under regulated price arrangements. On the other hand, the objective of the Demand Side Engagement Strategy is to provide transparency to the processes utilised by DNSPs to promote the engagement of non-network providers by increasing the ease with which non-network providers would be able to understand the processes involved and make contact with DNSPs. The Demand Side Engagement Strategy does not prescribe how the DNSPs should consider non-network alternatives, rather it is to encourage the engagement of non-network providers. For these reasons, we consider our findings in the two reviews to be consistent.

Demand Side Engagement Facilitation Process Document

The 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 providers. This facilitation process document would detail the processes adopted by DNSPs in their management and consideration of non-network proposals. For the facilitation process document to be effective, it would need to provide relevant information of assistance to non-network providers by identifying matters to be addressed in developing any non-network proposals. The type of information which we consider to be of benefit and able to be provided by each DNSP at reasonable cost is:

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

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

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

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

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

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

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

7. 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;

8. sources of relevant, publicly available information produced by the DNSP that non-network providers may access;

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

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

11. the DNSP's contact details; and

12. 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.

Given the increasing importance of the role of embedded generation, specific information relating to the processes for assessing embedded generation connection applications, the facilitation process document would also include:

- a summary of the factors the DNSP takes into account when negotiating connection agreements with embedded generators;

- the process used, and a summary of any specific regulatory requirements, for setting charges and the terms and conditions of connection agreements; and

- the process for lodging a connection application and the factors taken into account by the DNSP when assessing applications.

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 4 to 7 above), as these details would vary according to each proposal.[17]

However, these aspects of the facilitation process document would form the key components that non-network providers would consider in preparing proposals and assessing the economic feasibility of potential alternatives.[18] We consider that the

17 For example, EnergyAustralia noted in its submission on the Draft Report (p. 5) that "some aspects of the proposed content of the Facilitation Process document are difficult to provide in a meaningful or useful way and, as such, are overly prescriptive".

18 In submissions on the Draft Report, non-network providers supported the inclusion of this information and submitted that the information would be important to assist with the preparation of proposals. See, for example, the submission from Total Environment Centre (TEC), p.4.

information requested focuses on the processes that would, in any event, be adopted by the DNSP and the general principles that it applies in its decision making process. Although the detailed provisions for each project may differ, it is considered that there would be general processes and criteria that would apply to all projects.[19]

The implementation and delivery of the Demand Side Engagement Strategy are important considerations. We consider that there is no need for further specification on the content of the document or the development of explicit protocols or guidelines. The Rules should provide sufficient clarity in the requirements of the strategy and provide for DNSPs to comply with the provisions and to maintain the document, in the manner which reflects their own circumstances and interactions with non-network providers. However, we have recommended a review of the operation of the national framework in three years' time. It may be appropriate at that time to review whether guidelines should be established.

In addition, the facilitation process document is expected to be subject to on-going development and refinement as DNSPs refine their operational practices. At a minimum, the recommendations require the facilitation process document to be reviewed at least once every three years to reflect changes and developments in the requirements of stakeholders.

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.[20] The database would benefit both DNSPs and non-network providers by facilitating communications between the parties and assisting non-network providers to develop effective proposals that may be processed by DNSPs more efficiently.

DNSPs should be allowed to select from their existing materials information that, based on their experience, would promote the engagement with non-network providers and set out effective examples. 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. However, it is noted that as the database builds over time, information that may have been sensitive in the past may be able to be released and added to the database.

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[19] In its submission on the Draft Report, Ergon Energy (p. 5) submitted that the Facilitation Process Document was too prescriptive and disregards the DNSPs' internal processes. However, as discussed above, the recommendations provide for a description of the processes undertaken by DNSPs, thereby providing the flexibility for DNSPs to continue with their existing process where applicable.

[20] 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.

Demand Side Engagement Register

The recommendations require each DNSP to establish and maintain a "Demand Side Engagement Register", on which any stakeholder interested in engaging with the DNSP may request to be included.[21] DNSPs would be required to advise those on their Demand Side Engagement Register 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 registered parties to be advised of relevant information in a timely manner.[22]

2.5 Publication of Distribution Annual Planning Report

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
- accurately represents the relevant policies of the DNSP.

Each DNSP would conduct a public forum within three months of publishing its DAPR if requested to do so by a Registered Participant, Connection Applicant, Intending Participant or a stakeholder registered on its Demand Side Engagement Register.

Reasoning for recommendation

As required by the terms of reference for this Review, the 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 recommendations

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21 In its submission on the Draft Report, ENERGEX (p. 1, Annex A), suggested that the process of how non-network providers may register with the DNSPs be clarified. We note that some DNSPs may already have a similar process and should be able to adapt their existing processes. For this reason, we consider a general provision more appropriate.

22 It would be appropriate for each DNSP, rather than a third party, to maintain its own register as the purpose of the register is to facilitate and promote engagement of DNSPs and non-network providers.

require the DAPR to be published by 31 December each year, covering the forward planning period starting 1 January the following year.[23]

This publication timeframe 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 the 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.

EnergyAustralia currently plans and operates both distribution and dual function transmission assets. Given its function, EnergyAustralia submitted that it should be allowed to report on the planning of both its transmission and distribution assets in one report.[24] We consider that it would be sensible for each NSP to produce one comprehensive planning report covering all its assets and recommend that EnergyAustralia produces one report for all its network assets. [25]

Certification of the DAPR

The 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 represents the policies of the business. This would increase confidence in the content of the DAPR. As the DAPR would set out forecasts, which would be based on assumptions, certification would not be a commitment to achieving the forecast values and activities.

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 for the documents they produce. Stakeholders would also have the opportunity to register with DNSPs on the Demand Side Engagement Registry 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.

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23 In submissions on the Draft Report most stakeholders, including DNSPs and demand-side representatives, supported the publication timeframe of "by 31 December". ENERGEX submitted that it is currently required to publish its report by 31 August. We note that as the recommended timeframe is "by 31 December", ENERGEX could publish the report in accordance with it current practice.

24 EnergyAustralia, submission on the Workshop/Workshop Paper, p. 4.

25 In the Draft Report we sought comments on whether there were any objections to allowing EnergyAustralia to produce one comprehensive planning report. No objections were received on this issue.

DNSP public forum

To increase the transparency and accessibility of the information contained in the DAPR, the recommendations require DNSPs to conduct a public forum on their DAPR within three months of the report being published each year, if requested to do so by a Registered Participant, Connection Applicant, Intending Participant or a stakeholder registered on its Demand Side Engagement Register. The public forum would increase the ability of stakeholders to understand the information contained in the report through direct engagement with DNSPs.[26]

2.6 Joint Planning Requirements

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

Recommendation

Each DNSP would be required to undertake joint planning with any TNSP that 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.[27]

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.[28]

Reasoning for recommendation

The joint planning arrangements undertaken by TNSPs and DNSPs are important considerations in the national framework, given the volume of potential projects that affect both transmission and distribution networks.[29]

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26 Giving consideration to stakeholder comments, this recommendation has been amended where the draft recommendation had required a mandatory public forum.

27 This recommendation is consistent with the existing provisions for joint planning under the Rules. It clarifies that parties should use best endeavours to work together and meet regularly as required.

28 We note that the interaction of the timing of revenue resets and the incentive frameworks under Chapters 6 and 6A of the Rules may affect the relative incentives regarding joint planning. We have not assessed this potential risk and consider that such issues would be taken into account by the AER.

29 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.

Under the current Rules, TNSPs and DNSPs are required to undertake joint planning on an annual basis. The recommendations recognise that the current provisions and processes adopted by TNSPs and DNSPs appear to be working effectively.

The recommendations maintain the current provisions for joint planning while clarifying that the parties should meet regularly to carry out joint planning, which should already be occurring. The recommendations provide for parties to agree on a lead party for an investment. During the Review, we considered whether specific arrangements should be made for any situation where the parties cannot agree on a lead party. However, we consider that a joint obligation to work together is preferred as each NSP should retain control over the planning of the network which it operates and, for this reason, parties should jointly agree on a lead party if appropriate.[30]

Victorian Provisions[31]

In Victoria, DNSPs are responsible for planning and directing the augmentation of transmission connection assets under their licence conditions.[32] In other jurisdictions this is a TNSP responsibility. AEMO is responsible for planning and directing augmentations to the shared network, including carrying out appropriate cost benefit assessments under the NEL.[33] In cases where transmission connection investments require investments in the shared network, Victorian stakeholders have raised queries over the effectiveness of the processes adopted for the assessment of investments and whether the investments in the shared network (to support network to network connections) should be classified as prescribed or negotiated transmission services. To improve our understanding of the issues affecting Victorian joint planning we arranged a meeting with the Victorian stakeholders, which was held on 26 August 2009.[34]

Having considered the issues raised by Victorian stakeholders, we consider that the proposed recommendations for joint planning can also be applied in Victoria as they clarify the obligation for both parties to cooperate and work together in identifying and planning the most economic investments in one planning process. We note that in practice the interaction of more than one regulatory instrument could potentially result in areas that would require clarification. We understand, that in the case of joint planning in Victoria, the stakeholders would be prepared to continue working together to develop effective arrangements and processes for joint planning and assessing investments.

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30 In its submission on the Workshop/Workshop Paper (p. 3), SP Ausnet noted 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.

31 Additional information outlining the issues in Victoria, as raised by stakeholders, is provided in Appendix G.

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

33 Section 50F of the NEL.

34 The meeting was attended by the Chairman and staff of the AEMC, and representatives from the Victorian distribution business, AEMO and the Victorian Department of Primary Industries.

The requirement to apply one regulatory investment test, as discussed in section 2.5.2 below, would go towards addressing the concerns raised by clarifying that one joint regulatory test must be conducted. The RIT-T requires the assessment of the potential market benefits which would provide that any joint investment would be justified on the basis of net economic benefits.

During the meeting with Victorian stakeholders, there was discussion of developing a Memorandum of Understanding (MOU) between the parties as a means of clarifying and specifying the objectives and processes for joint planning.

We recommend that such an MOU be developed and implemented by the Victorian parties. The MOU could set out provisions for the overall joint planning process such as:

- when the joint planning process should commence;
- clarifying the types of projects that would be considered in the joint planning process;
- what information would be provided to each party throughout the planning process;
- how technical assessments would be carried out and what factors would be taken into account;
- whether a lead party would be appointed for carrying out the RIT-T and how the lead party would be determined;
- whether any cost thresholds for the shared network component of projects would apply and how would the threshold impact on the technical and economic analysis that would be required; and
- how parties would address disputes.

We consider that an MOU would go towards addressing the issues in Victoria and would allow the parties to provide input into developing a process that would be reflective of their specific requirements.

A further issue in joint planning in Victoria appears to be the application of the definition of "prescribed transmission services". Part (c) of the definition of a prescribed transmission service, as set out in Chapter 10 of the Rules, states that "connection services that are provided by a Transmission Network Service Provider to another Network Service Provider to connect their networks where neither of the Network Service Provider is a Market Network Service Provider" would be a prescribed transmission service. However, the Victorian stakeholders report that there have been disagreements between the distribution businesses and AEMO as to whether investments in the shared network required to facilitate a network-to-network connection falls under the definition of a prescribed transmission service.

Having regard to the views of the Victorian stakeholders, AEMO and Grid Australia,[35] we note that this issue requires further consideration and analysis. We will liaise with stakeholders to evaluate whether a Rule change proposal seeking a clarification of the definition of prescribed (and negotiated) transmission services would be appropriate . In addition, we note there may be broader issues relating to cost recovery such as the queries raised about the provisions for the recovery of charges for transmission use of system services under the Rules.[36] We will consider whether these issues are related and how they may be best addressed.

2.6.2 Regulatory Investment Test for Investments identified through Joint Planning

Recommendation

Where the necessity for augmentation or a non-network alternative is identified by the process under the joint planning provisions, including for transmission-distribution network to network connections services, NSPs:[37]

- would jointly determine plans that can be considered by relevant stakeholders;
- would carry out the Regulatory Investment Test for Transmission (RIT-T) for the options identified;[38]
- 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 recommendation

The recommendations provide that the RIT-T would apply to joint investments as the RIT-T requires that a broader range of market benefits 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

35 Grid Australia, in its supplementary submission on the Draft Report (p. 1), noted that it considers the Rules to be clear that a connection service provided by a TNSP to connect to the network of another NSP is a prescribed transmission service.

36 In their joint submission on the Draft Report, Victorian distribution businesses (p. 9) proposed that clause 6.18.7 of the Rules, recovery of charges for transmission use of system services, should be amended to provide for the full pass-through of all charges levied on a distribution business in relation to transmission services.

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

38 For the avoidance of doubt, the RIT-T threshold would apply to joint investments.

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).

Transmission-distribution network-to-network connection services would be one of the key investments that would require joint planning to ensure the investments in each of the networks (and the shared network) were appropriately coordinated. The RIT-T would also apply to these investments to provide that the most economically efficient solution would be identified. To clarify these requirements, the RIT-T provisions would need to be amended to provide for the assessment of transmission-distribution connections, which are currently excluded from the RIT-T.

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 recommendations provide that the RIT-T apply to joint investments, as it would provide for a comprehensive assessment of investment options, whilst maintaining flexibility.[39]

2.6.3 Joint planning between Distribution Network Service Providers

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

Reasoning for recommendation

In jurisdictions where there are multiple distribution networks and DNSPs, investments that affect more than one network would require DNSPs to plan jointly. 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.

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39 Although the majority of stakeholders supported the application of one regulatory investment test to joint investments, most DNSPs supported the application of the RIT-D. (See for example the submission on the Draft Report from ENA, p. 13). DNSPs submitted that there are a large number of joint investments that are driven by distribution requirements and, as such, do not have any market benefits. However, we note that in these situations, the RIT-T provides for a least-cost assessment to be conducted.

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3 Reporting Requirements

This Chapter discusses the recommendations on the reporting requirements under the annual planning process. It describes each proposed section of the Distribution Annual Planning Report (DAPR) and sets out 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 recommendations propose that the scope of reporting should only encompass a section of the planning activities undertaken. 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 publishing the information.

Summary of recommendations

7. The DAPR would include forecasting information over the required planning period. This would include capacity and load forecasts at the sub transmission and zone substation level, and, where they have been identified, overloaded primary distribution feeders.[40]

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

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

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

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

12. A summary of the DNSP's activities and actions taken to promote non-network initiatives, including embedded generation, and inform on any significant investments in metering services.[41]

[40] The recommendation has been clarified to require information on overloaded primary distribution feeders "where they have been identified".

[41] The requirement for regional development plans and the DNSP's plans for demand side activities have been included in the final recommendation.

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 providers to identify potential investment opportunities that could be exploited through further dialogue with DNSPs.

Customers should be able to use the annual planning reports to optimise investments and promote efficient decision making. The reports should also assist stakeholders 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.

We note that the AER is currently consulting on a proposed regulatory information order (RIO) that would require DNSPs to submit and publish annual information relating to the service target performance incentive scheme.[42] The RIO would likely focus on collecting relevant cost and expenditure information to assist the AER with its monitoring and enforcing requirements. As the DAPR would provide information on forecast system limitations and potential solutions, the DAPR would support the information that would be available under the RIO.[43] We note that the AER supported the planning and reporting requirements and considered that the DAPR would provide transparency and accountability to DNSP's actions and would assist the AER in its regulatory and enforcement functions.[44]

3.2 Context of the Planning Report

As outlined in Chapter 1, the DAPR 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. We have made the recommendations on the basis that the current jurisdictional arrangements for reporting (and project assessment) would be rolled back once the national arrangements are in place.

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42 The RIO was noted by DNSPs in submissions on the Draft Report, see for example the submission from Integral Energy, p. 5.

43 The AER, in its submission on the Draft Report (p. 1), supported the proposed planning and reporting framework

44 AER, Submission on the Draft Report, p. 3.

The 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 of system limitations, particularly considering the different planning and forecasting methodologies used by DNSPs across the NEM. The information published in the DAPRs would be supported by the Demand Side Engagement Strategy where the information contained in a DAPR would promote further engagement between DNSPs and non-network providers.

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 regulatory costs for DNSPs. A comparison of the recommendations and the current jurisdictional reporting requirements is provided in appendix D.[45]

3.3 Addressing the Principles for the Review

Economic Efficiency

The reporting requirements of the proposed DAPR are consistent with the economic efficiency principle as they provide information that allows stakeholders to more effectively identify potential areas for non-network alternatives and other investments (e.g. embedded generation).

Transparency

The reporting requirements of the DAPR are consistent with the transparency principle as they would require DNSPs:

- to explain the planning methodology and forecasting methodology they utilise, including any underlying assumptions. This is especially important given the different methodologies used by DNSPs;
- to report system limitations in a consistent manner, including any system limitations on primary distribution feeders (where they have been identified);
- to provide a summary of the investments they have undertaken;
- to report on the joint planning activities that they have undertaken; and

[45] In our Scoping and Issues Paper (p. 33), 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. It is considered that outlining the reporting provisions in the Rules promotes certainty and stability of regulatory outcomes. In developing the 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.

- to provide a high level summary of their asset management strategies and plans for demand side engagement.

Proportionality

The reporting requirements of the DAPR are consistent with the proportionality principle as they would:

- be restricted to the major assets of sub-transmission lines, zone substations and primary distribution feeders;

- provide for DNSPs to maintain their existing processes for forecasting and planning so long as the methodology and assumptions are explained in the DAPR;

- require reporting on primary distribution feeders only where overloadings have been identified;

- require reporting on investments at a summary level and reporting in some cases would be limited by a capital cost threshold of $2 million.

Technological Neutrality

The reporting requirements of the DAPR are consistent with the technological neutrality principle as they would require DNSPs to identify potential solutions to system limitations giving consideration to network and non-network options and any load transfer capability. This would then be supported by the qualitative information on planned demand side developments. By reporting the information in a consistent and transparent manner, potential investors would also be able to assess the information that has been published.

Consistency across the NEM

The reporting requirements would provide for consistent information to be published in each jurisdiction. This would contribute to ensuring a level-playing field in terms of providing information to potential investors.

Fit for Purpose, Reflecting Local Conditions

The reporting requirements provide for each DNSP to maintain its own planning and forecasting methodology. By requiring system limitations to be identified in accordance with the cause of the limitation would also provide flexibility in the process and ensure that specific jurisdictional requirements would be able to be reflected in the DNSPs' reporting. In addition, the reporting framework recognises there may be specific requirements that a particular jurisdiction may wish to include.

Building on Existing Jurisdictional Requirements

The recommendations were developed giving consideration to the existing jurisdictional requirements for planning and reporting to ensure the integrity of the current provisions are maintained.

Consistency with Transmission Planning Framework

The recommendations were developed giving consideration to the transmission planning framework.

3.4 Scope of the Reporting Requirements

Recommendation

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

- relate to the power system; and
- are sub-transmission assets or zone substations or, on an exception basis, primary distribution feeders.

Reasoning for recommendation

The DAPR should provide sufficient information to allow non-network providers 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.

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.[46]

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. DNSPs will also be required to inform on any significant investments in metering services. As distribution businesses become more "active" and employ smart grid technologies to manage flows and constraints more efficiently, it is important that the DAPR informs stakeholders on such projects.

3.5 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

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46 The Draft Report (p. 27) sought comments on the appropriate definitions of "sub transmission assets" and "primary distribution feeders". Submissions on the Draft Report (see for example the submission from ETSA Utilities, p. 5) provided comments in these areas. Taking the submissions into consideration, the definitions have been amended such that they are based on the functionality of the assets rather than in reference to specific voltage levels. This approach would ensure that the definition captures all the required assets, as set out in the draft Rules.

identify these factors. The DAPR would also require forecasting information to be published.

3.5.1 Forecasting

Recommendation

The DAPR would include forecasts for the forward planning period, including at a minimum:[47]

1. a description of the forecasting methodology used, sources of input information, and the assumptions applied;
2. forecasts for transmission-distribution connection points, zone substations, sub-transmission lines; including:[48]
   - total capacity; and
   - firm delivery capacity (summer and winter);
3. load forecasts for transmission-distribution connection points, zone substations, sub-transmission assets; including:
   - peak load (summer or winter);
   - number of hours per year that 95% of peak is expected to be reached;
   - power factor at time of peak load; and
   - load transfer capability;
4. forecasts of future transmission-distribution connection points and zone substations, including: location, future loadings, estimated timing (month, year) of the connections, and the level of embedded generation;
5. forecasts of reliability targets in accordance with regulatory requirements; and
6. forecasts of any factors that may have a major effect on the *distribution network* and *sub transmission network*, including factors affecting:
   - fault levels;
   - voltage levels;
   - other system security requirements; and
   - ageing and potentially unreliable assets.

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[47] The requirements set out that a DNSP should prepare forecasts to the "best of its ability". In its submission on the Draft Report, Energy Australia (p. 3) queried why this clarification was necessary as DNSPs would be best placed to produce forecasts. For clarity, this reference has been removed.

[48] A new definition for transmission-distribution connection points would need to be introduced in the Rules. It is proposed, as outlined in the draft Rules, that the definition be "the agreed point of supply established between a Transmission Network Service Provider and a Distribution Network Service Provider".

In addition, where identified by the DNSP, the DAPR should specifically include information on any primary distribution feeders that have exceeded in the current year, or were forecast to exceed within the next two years, 100% of the normal cyclic rating (summer or winter) under normal operating conditions. The information to be provided would include:[49]

1. the location of the primary distribution feeder;
2. the extent of overload experienced in the current year;
3. the forecast load in the next two years, and identifying the extent the forecast load would exceed the normal cyclic rating (summer or winter);
4. any potential solutions being considered by the DNSP to address the overload; and
5. where an estimated reduction in forecast load would defer the overload for a period of 12 months, include:[50]
   - the year and month in which a overload forecast to occur;
   - the relevant connection points at which the estimated reduction in forecast load may occur; and
   - the estimated reduction in forecast load in MW needed.

Reasoning for 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.[51]

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49 In submissions on the Draft Report (see for example EnergyAustralia, p. 9), DNSPs noted that forecasting and monitoring of primary distribution feeders would normally be conducted on a cyclic basis as the costs required to prepare annual forecasts were prohibitive. We have clarified that information on primary distribution feeders should be included where it has been identified by the DNSP.

50 This clause is consistent with the provision 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.

51 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 (see, for example, submission from ENERGEX on the Scoping and Issues

Information on any overloaded primary distribution feeders that have been identified by the DNSP would also enhance the ability of stakeholders to identify feasible opportunities for embedded generation and demand management.

The recommendations require a summary of the forecasting methodology adopted by DNSPs, including an explanation of any assumptions applied. This is especially important given the different forecasting methodologies used by DNSPs.

3.5.2 Definition of system limitations

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:

1. forecast load exceeding system capability;
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; and
6. the requirement to meet any other regulatory obligations.

Reasoning for recommendation

The concept of a system limitation is intended to reflect a problem that has been identified on the network or a "constraint" on the network.[52] 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.

To ensure that the information provided is comprehensive and consistent across jurisdictions, the 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 other jurisdictional obligation (including System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI)). This has been included in the 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.[53]

Paper, p.6). For these reasons, the recommendations do not include the requirement to produce forecast DLFs.

52 It is noted that the Scoping and Issues Paper had sought comments on the appropriate definition of a "network constraint".

53 In its submission on the Draft Report, ETSA Utilities (pp. 5-6) suggested that system limitations should be defined in terms of the planning criteria used by the individual DNSP and not in generic

3.5.3 Reporting on system limitations

Recommendation

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

1. the location and best estimate timing of the system limitation;[54]
2. 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;
3. impact of the system limitation, if any, on the capacity at the transmission connection points;
4. discussion of the potential solutions that may address the system limitation in the forward planning period, if a solution is required; and
5. where an estimated reduction in forecast load would defer a forecast system limitation for a period of 12 months including: the best estimate timing 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.[55]

Reasoning for recommendation

Including information on the location of the system limitation and the cause of the system limitation would enable stakeholders to make efficient decisions and non-network providers to propose feasible credible alternatives. Information on options to be considered by DNSPs to address a system limitation is also beneficial to stakeholders.

Information on load 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.[56]

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terms. However, as the planning criteria differs across each jurisdiction and the methodology used differs across each DNSP, defining system limitations in accordance to the underlying causes provides clarity and flexibility in the current environment. The recommendations would provide for each DNSP to continue with its existing planning methodology.

54 In its submission on the Draft Report, Ergon Energy (pp. 14-15) submitted that it currently forecasts the timing of any system limitations according to the season in which the limitation would occur. We note that forecasts are subject to assumptions and could change given changes in other circumstances. However, we would expect that DNSPs would be able to provide an estimate of the timing of the constraint to the best of their ability. The requirements have been clarified to reflect this consideration.

55 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.

56 While some DNSPs supported including load transfer capability information, Ergon Energy noted, in its submission on the Scoping and Issues Paper (p. 8) that it did not support the inclusion of such information as the impacts would not be static and would be subject to changes to load flow over the network. However, as discussed, we note that forecast information would be subject to changes.

Information in the DAPR, including information on load 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 providers to consider and assess potential investments and to promote further discussions and communications with DNSPs.

The recommendations would require DNSPs to include a summary of their planning methodology in their DAPR. 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 recommendations allow DNSPs to utilise their own planning methodologies to forecast and provide appropriate information, so long as their assumptions are clearly set out.

3.6 Reporting on Network Investments

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;

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

3. other committed projects that were exempt from the RIT-D on the basis of being urgent or unforseen, or replacement and refurbishment projects – summary of projects.

Reasoning for 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.[57]

[57] In submissions on the Draft Report, some DNSPs (see for example the submission from ENA, p. 15) submitted that including information on investments in the DAPR would duplicate reporting requirements. DNSPs should be able to reference other documents where required. However, we note that the DAPR requires a summary only and would specifically be a central source of information for stakeholders.

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.

To capture, and provide transparency to, investments that fall outside the RIT-D process, reporting on any other committed projects with a capital cost of $2 million or more would be required.[58] A threshold of $2 million has been set to capture the replacement and refurbishment investments that could have a material impact on the distribution network, which may provide the potential for non-network solutions. The $2 million threshold would also apply to urgent and unforseen investments to provide a discipline to ensure that the DNSPs undertake sufficient planning to identify investment needs and not utilise the urgent and unforseen provision unnecessarily.[59]

3.7 Other Reporting

To support the key information on system limitations, the 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.

3.7.1 Description of the network

Recommendation

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

Reasoning for 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 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

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58 In its submission on the Draft Report, ENA (p. 17) noted that clarification is required as to how replacement/refurbishment projects should be treated – individually or as a group. We note that the projects should be treated in terms of the problem or system limitation that is being addressed.

59 In submissions on the Draft Report, some DNSPs (see for example the submissions from EnergyAustralia, p. 9, and ENERGEX, p. 2, Annex B) requested clarification for the types of refurbishment or replacement projects that should be included. The requirement only extends to the scope of the reporting process – that is, zone substations, sub-transmission assets and primary distribution feeders.

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.

3.7.2 Joint planning

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 recommendation

As discussed in Chapter 2, TNSPs and DNSPs would be undertaking joint planning to identify any joint investment requirements. The 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). For these reasons, a similar level of reporting for joint planning activities between DNSPs has also been included.

3.7.3 Performance standards and compliance

Recommendation

A high level of information on performance standards (including the relevant jurisdictional requirements) 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 recommendation

Performance standards impact on 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 providers that operate in more than one jurisdiction and increase the transparency to regulators.[60]

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60 The Scoping and Issues Paper (p. 16) raised the issue of whether historical data should be included on network performance. 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 (see for example, Jemena in its submission on the Scoping and Issues Paper, p. 3). Energy Response on the other hand, believed that information should be included on historical performance, including how DNSPs have performed compared to previous forecasts. In response to these considerations, the recommendation requires qualitative information as discussed above.

The 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.

3.7.4 Regional Development Plans

Recommendation

A regional development plan would be included in the DAPR. The regional development plan would provide a map of the DNSPs' network, identifying each specific planning region as categorised by the DNSPs or required by jurisdictional requirements.

Reasoning for recommendation

Regional development plans would include a map or maps of the DNSPs' network, identifying the major assets of sub-transmission lines, zone substations and transmission-distribution connection points. It would also provide a summary of the forecast capacity and reliability targets for each region. Any system limitations forecast for the major assets would also be identified on the map along with any identified overloaded primary distribution feeders. These regional development plans would assist non-network providers and other investors to efficiently identify the location of forecast system limitations and potential opportunities for investment and further investigation. The plans would also provide useful information to regional communities and increase the transparency of the planning activities undertaken on a regional basis. Although some DNSPs did not support the inclusion of regional development plans on the basis of the potential costs,[61] as DNSPs would already be required to identify the location of system limitations and would likely have existing provisions to produce maps of their network, the requirement would unlikely add any significant costs to DNSPs. On the other hand, other stakeholders saw benefits in regional development plans being produced as they would assist users with clearly identifying constraints in particular areas.[62]

61 See for example the submission from Aurora Energy, p. 5

62 See for example the submission from CUAC, p. 3. The submission from the South Australian Government also supported the inclusion of regional development plans, noting that it is currently a requirement on ETSA Utilities to produce such a plan for South Australia.

3.7.5 Demand Side Developments and Other Significant Investments

Recommendation

A high level, qualitative summary of the demand side activities planned by the DNSPs in the forward planning period, including planned actions and developments under the Demand Side Engagement Strategy, and any other significant investments (such as investments in "smart" technology) would be included in the DAPR. This qualitative summary should also include information on the non-network solutions and activities the DNSPs have undertaken in the past year.

Reasoning for recommendation

As discussed in Chapter 2 of this Report, the objectives of the national framework would be met through the interaction of all components of the framework. To support the Demand Side Engagement Strategy, a qualitative summary of the demand side activities planned by DNSPs would promote the continued development of demand side activities. Given the increasing importance of real time metering and the utilisation of smart technology in impacting performance and demand side participation, any significant investments in smart technology would also be included.[63]

3.7.6 Asset management

Recommendation

A summary of the business' asset management methodology should be included in the DAPR.[64]

Reasoning for 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 business goals, by maximising the asset value through the optimisation of asset performance over the total asset lifecycle. For these reasons, asset management has a direct influence on network planning. As noted by the Victorian Department of Primary Industries (DPI), DAPRs would be used by governments as a tool to provide assurance that electricity networks were planned and operated in a safe, reliable and cost efficient manner.[65]

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63 Having considered the issues raised in submissions, we consider that providing a high level summary of investments would provide transparency to the investments and, where non-network providers may be interested in additional information, they would be able to approach the DNSP through the processes under the Demand Side Engagement Strategy.

64 Having considered the issues raised in submissions, we consider that asset management has a direct influence on planning as discussed above. The summary information that is requested would be at a high level and DNSPs would likely be able to provide a high level summary without incurring significant costs.

65 Victorian DPI, Submission on the Draft Report, p. 1.

The requirement for a summary of the asset management methodologies goes towards meeting this purpose.

This 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.

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4 Regulatory Investment Test for Distribution

This Chapter sets out the Commission's 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 is provided in Appendix E.1.

The Chapter describes the scope of investments which would be subject to the RIT-D, the assessment framework of the test itself, 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 starting basis and have made amendments in recognition of the nature and volume of investments undertaken at the distribution level. The Rules governing the RIT-D would be supported by the development of the RIT-D test and accompanying application guidelines by the AER.

Summary of recommendations

13. The purpose of the RIT-D would be to identify the preferred option which would be the credible option which maximises the present value of net economic benefit to all those who distribute electricity in the market. For the avoidance of doubt, a preferred option may, in the relevant circumstances, have a negative net economic benefit (i.e. a net economic cost) where the identified need is for reliability corrective action.[66]

14. The RIT-D would be undertaken by DNSPs when a distribution system limitation exists and the estimated capital cost of the most expensive option to address the relevant identified need which is technically and economically feasible is $5 million or more.[67]

15. The RIT-D would not apply to urgent and unforseen investments, negotiated services, replacements, customer connection services, or where the proposed investment has been identified through joint planning processes between DNSPs and TNSPs.[68]

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.

66 The purpose of the RIT-D has been amended so that it is consistent with the purpose of the RIT-T.

67 The RIT-D threshold has been changed from $2 million outlined in the Draft Report to $5 million. Minor clarifications have also been made to the recommendation.

68 The exemption of connection services has been extended to all connection services.

17. The RIT-D would involve:[69]

- an initial screening test, the Specification Threshold Test (STT), to determine the appropriate consultation and reporting requirements;
- a project specification stage, where DNSPs would be required to consult on alternative proposals to meet the identified need before the project assessment process. The recommended period for consultation is four months and will be limited to identified needs which pass the STT; 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 option to decide which market benefits would be included.

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 providers 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 providers 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.

However, the potential costs associated with the RIT-D would fall predominantly on DNSPs and would relate to the costs and resources required by DNSPs to comply

69 The accelerated consultation option for DNSPs as outlined in the Draft Report has been removed. The consultation period has been changed to four months.

with the Rules requirements and the potential for the regulatory process to delay investments.

4.2 Addressing the Principles for the Review

In developing our recommendations for the RIT-D, we have taken into consideration the following principles for the Review.

Economic Efficiency:

The recommendations for the RIT-D support the principle of economic efficiency by:

- amalgamating the reliability and market benefits limbs of the current Regulatory Test into a single project assessment process under a cost-benefit framework; and
- giving DNSPs the option to include possible market benefits in their project assessments.

Transparency:

The recommendations for the RIT-D achieve the principle of transparency by:

- requiring the DNSP to consult, where appropriate, via a draft project assessment report;
- requiring the DNSP to report on each project assessment findings and the reasons for the preferred option in either a final project assessment report or in the DAPR; and
- providing the ability for stakeholders to raise disputes with the AER on all projects which are subject to the RIT-D.

Proportionality:

The recommendations for the RIT-D achieve the principle of proportionality by:

- setting the RIT-D threshold to be the same as the RIT-T threshold of $5 million;
- applying a limited cost benefit approach under the RIT-D where DNSPs are provided with the option to quantify market benefits; and
- subjecting only investments which are likely to benefit from additional reporting and consultation to the project specification stage.

Technological Neutrality:

The recommendations for the RIT-D achieve the principle of technological neutrality by:

- specifying the decision making criteria that DNSPs must use when assessing different investment options and requiring them to report and publicly consult on their decision making processes;

- providing non-network providers with an opportunity to put forward proposals to meet the identified need at the project specification stage; and

- changing the definition of credible option so that the absence of a non-network proponent would by itself not exclude a non-network option from being assessed.

Consistency across the NEM:

The recommendations for the RIT-D achieve the principle of consistency across the NEM by:

- having a common project assessment process which would be applied to all distribution investments across the NEM;

- prescribing in the Rules the classes of market benefits and costs that should be considered during the project assessment process; and

- setting out the principles in the Rules that the AER must adopt in developing the test and the RIT-D guidelines.

Fit for Purpose, Reflecting Local Conditions:

The recommendations for the RIT-D achieve the principle of fit for purpose by:

- exempting defined investments from the RIT-D and tailoring DNSPs' reporting and consultation requirements to the characteristics of each identified need;

- applying a limited cost benefit approach under the RIT-D where DNSPs are provided with the option to quantify market benefits; and

- designing the STT to tailor the consultation and reporting requirements to each identified need.

Consistency with Transmission Planning Framework:

The recommendations for the RIT-D achieve the principle of consistency with the transmission planning framework by:

- applying the same decision making criteria to distribution and transmission investments; and

- requiring the AER to undertake its review of the cost thresholds for the RIT-D in conjunction with its review of the RIT-T cost thresholds by 31 July.

See Appendix E.3 for a summary of the differences and similarities between the RIT-D and RIT-T.

4.3 Amalgamation of reliability and market benefits limbs

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 benefit, subject to meeting jurisdictional reliability standards (where they apply).

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.

A reliability corrective action refers to an investment by a DNSP in respect of its distribution network for the purpose of meeting the service standards linked to the technical requirements of schedule 5.1 of the Rules or in applicable regulatory instruments. This is similar to the process under the RIT-T.

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 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.

Assessment of Market Benefits

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.

From 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 in 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 is needed to ensure that only efficient investment occurs.[70]

The risk of DNSPs assessing only those market benefits that validate their preferred investments, should be minimised by requiring DNSPs to state their reasons in their

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70 In their submissions on the Draft Report, ENA and EnergyAustralia considered that there must be the ability for refurbishment or replacement projects, which results in augmentation to the network and the augmentation component cost is $2 million or greater, to have a negative net economic benefit. However, we have not accepted this, because negative net present value should only be permitted if the project is a reliability corrective action. Also we are concerned that including such an exception as suggested could create a preserve incentive to classify augment projects as replacement and may make it more difficult to ensure compliance with the objective of the RIT-D.

project assessment reports for their preferred option and by the ability for stakeholders to raise disputes with the AER.

DNSPs would also be required to take into account any submissions they receive on either their project specification report and/or draft project assessment report before finalising their preferred option in their final project assessment report. These consultation processes would provide the opportunity for stakeholders to put forward any applicable market benefits which, if quantified, have the potential to alter the DNSP's preferred solution.

4.4 Scope of investments subject to the RIT-D

Recommendation

The cost threshold for proposed investments subject to the RIT-D would be set at $5 million and be applied to the estimated capital cost of the most expensive option that is technically and economically feasible to address the relevant identified need.

Reasoning for recommendation

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.[71] This threshold for the Regulatory Test was established in 2001 and since then there have been real increases in the input costs of distribution assets. 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.

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 this reason, we recommend that an initial screening test, the Specification Threshold Test (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 appropriate process DNSPs must apply for each investment. Investments which do not meet the requirements of the STT would be subject to a process with more limited reporting and consultation.

RIT-D cost threshold

The Draft Report proposed that the cost threshold for the RIT-D be set at $2 million, lower than the threshold of $5 million under the RIT-T, on the basis that distribution investments on average have a lower capital cost than transmission investments.

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71 See clause 5.6.2(g) of the Rules.

Nevertheless, submissions from NSPs generally considered that the threshold for the RIT-D should not be set lower than $5 million. The AER also noted that a $5 million threshold would maintain consistency with the RIT-T and reduce regulatory burden. On the other hand, non-network providers and advocacy groups considered that the threshold for the RIT-D should be set far lower.

We now recommend the cost threshold for the RIT-D be set at $5 million. It is considered that this threshold of $5 million would provide an appropriate balance between the regulatory burden placed on DNSPs and the need for a detailed, transparent decision making process while also ensuring distribution investments proceed in a timely manner. This would also effectively focus the RIT-D on more significant investments.

Further, although the threshold for the RIT-T would be the same as that proposed for the RIT-D, investments which are subject to the RIT-T are required to undergo more rigorous reporting, consultation and assessment. By contrast, DNSPs would have greater flexibility and discretion under the RIT-D, as the processes can be tailored to the characteristics of each identified need.[72]

We also recognise that there is greater potential for small scale non-network solutions to meet an identified distribution need. It may be perceived that 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. We consider that the development of smaller distribution investments that have non-network options would be assisted by the Demand Side Engagement Strategy and the increased reporting of system limitation information under the DAPR. It is therefore the interaction between the Demand Side Engagement Strategy, the DAPR and the RIT-D that would achieve the overall objectives of the national framework. Furthermore, the revenue determination framework under Chapter 6 of the Rules places a discipline on DNSPs to make efficient investments and therefore to explore possible non-network options where appropriate.

We note concerns raised in the submissions regarding the complexity of the overall RIT-D. We consider that with the increase in the RIT-D threshold to $5 million, this would reduce the complexity created by the need for additional processes to allow for flexibility. Therefore, we consider that the RIT-D process is now more straightforward for DNSPs to apply and for market participants to understand and engage in. 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 stakeholders to understand how it would be applied.

72 For example, as the RIT-T does not have an initial screening test, all transmission investments are subject to the RIT-T and 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.

Most expensive technically and economically feasible option

It is appropriate to apply the threshold to the most expensive option which is technically and economically feasible, rather than the preferred solution. We note that this definition was adopted for the RIT-T and consider that the definition is appropriate as other definitions such as "most likely option" would imply that a decision had already been made on an appropriate investment.

In the Review of Demand-Side Participation in the National Electricity Market, our draft findings concluded that the existing triggers for consultation, and their link to augmentation options, are causing bias, and therefore act as a barrier, to demand-side options being given due consideration.[73] Because the thresholds for consultation arrangements are based on the most likely network option, the network option becomes the benchmark for assessment, rather than any other credible option that may address the identified need.

We noted that this bias was addressed as part of the RIT-T by requiring that the test be undertaken when a transmission planning issue exists and the most expensive economically credible option is estimated to cost more than a threshold dollar amount. Therefore, we considered that it may be appropriate for similar changes to be made for distribution network planning in this Review.

Furthermore, DNSPs should therefore be encouraged to undertake STTs earlier in the planning process. Linking the threshold to the most likely option may unnecessarily delay the assessment process and may mean DNSPs are less receptive to alternative options.

4.4.1 AER review of cost thresholds

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. The cost threshold which is used in the requirements for the DAPR would also be subject to this review.

Reasoning for recommendation

A periodic 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. 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. [74]

[73] See AEMC 2009, Review of Demand-Side Participation in the National Electricity Market, Stage 2: Draft Report (29 April 2009, Sydney), pp. 40-41.

[74] 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

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. 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.

4.5 Exemptions from the RIT-D

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 the RIT-D threshold;[75]
- urgent and unforseen investments;
- investments designed to ensure that 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;
- customer connection assets[76];
- investments related to the refurbishment or replacements of assets which are not intended to augment the network; and
- 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 $5 million.

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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.

75 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.

76 If the customer connections requires augmentation to the shared network, then the augmentation (if more than the RIT-D threshold) will be subject to the RIT-D.

DNSPs would be required to report on the details of any urgent and unforseen or replacement and refurbishment investments in their DAPR, where the estimated capital cost of such investments is $2 million or more.

4.5.1 Exemptions from the RIT-D - Replacement investments

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 the augmentation component has an estimated capital cost of $5 million or more, these investments would be subject to the RIT-D.

Reasoning for recommendation

Inclusion of replacement investments may 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 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. 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.

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 $5 million, the replacement investment would be subject to the RIT-D. 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.

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

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 six months of the DNSP identifying the need for investment; and
- the event or circumstances causing the identified need was not reasonably foreseeable by, and was not beyond the reasonable control of, the DNSP; and
- a failure to address the identified need is likely to have a material adverse affect on the reliability and secure operating state of the distribution network.

Reasoning for 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. The same exemption is in place for transmission investments under the RIT-T. It should be noted that this exemption is not intended to include customer connections which may be required at short notice, as negotiated services and customer connections would be exempt from the RIT-D.

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. The increase in the RIT-D threshold to $5 million also supports this intention. We also consider that the definition of "urgent and unforeseen" should be consistent with that used for the RIT-T which is where this term was previously applied.

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.

4.5.3 Inclusion of primary distribution feeders in RIT-D

Recommendation

Investments required to address a network issue on a primary distribution feeder would not be exempted from the RIT-D.

Reasoning for recommendation

DNSPs currently undertake a large volume of investments to augment primary distribution feeders. We previously proposed in the Draft Report that these investments may be exempted from the RIT-D because, if not exempted, there was a risk that the RIT-D may impose a significant regulatory burden on DNSPs.

Given the increase in the RIT-D threshold from $2 million to $5 million, the rationale for an exemption diminishes. The number of such investments subject to the RIT-D would now be reduced. We consider that this provides an appropriate balance between simplifying the process and placing a regulatory discipline on DNSPs.

4.6 Specification Threshold Test (STT)

Recommendation

The STT would apply for all investments that are subject to the RIT-D.

Under the STT, DNSPs would be required to assess:

- the reasons for the investment; and
- 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.

A general consultation process with any customers that may be adversely affected by an investment would be included before the preferred option is commissioned.

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 the 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 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.

Reasoning for recommendation

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. For investments where there was potential for non-network solutions, this would ensure that non-network providers have an opportunity to put forward alternative proposals to address the identified need during the project specification stage.

We also consider that there is 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 non-network solutions. This is to strike the right balance between the compliance cost on

DNSPs and the benefits of additional consultation. Therefore, we propose 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.

DNSPs would be required to publish a report outlining the results of the assessment if their investments do not pass the STT. The requirement of this report is to provide transparency and certainty.

Materially adverse impact on customers

We discussed in our Draft Report that it would be appropriate for the STT to assess the material potential for the identified need to impact adversely on end use customers' quality of service. For investments where there may be an adverse impact on end users' quality of service, this would have required 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.

However, DNSPs were unclear as to the intent of the requirement relating to the potential for the identified need to adversely impact on the quality of service and questioned how practicable it would be to apply this provision.

We consider that there are benefits from requiring the DNSPs to directly consult with any customers who would be adversely impacted from a proposed investment. However, it would likely be more appropriate for any consultation to occur once the preferred option has been identified and specified than on a possible spectrum of options during the project specification stage. Therefore, we suggest including a general provision to consult with affected customers be provided outside of the RIT-D process. Further work on clarifying the definition of "adverse impact" is required. This is a matter appropriate for consideration as part of any Rule change request relating to these recommendations.

4.7 Project Specification stage

4.7.1 Requirements of the project specification report

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 need for investment;

- the annual deferred augmentation charge, which is the value of any deferral in the network solution;[77]
- 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
- to the extent practicable, a description of possible investment options to meet the identified need, including:
  - a technical definition or characteristics of the option;
  - estimated construction timetable and commissioning date; and
  - 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 non-network providers to engage constructively on the project specification report.

Reasoning for recommendation

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. Having considered comments in submissions on the Draft Report, we do not consider that DNSPs are required to "second guess" potential non network solutions and therefore have amended the provision to require the DNSPs to provide information to the extent practicable. Nevertheless, the DNSPs would be in a position to use their best endeavours to understand the potential solutions that may address their network issues whether they are "network" or "non-network" solutions.

At this stage, non-network providers 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.

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 providers and facilitate the uptake of non-network solutions, where they are the most efficient option to address the identified need.

77 This provision has been included giving consideration to ETSA's submission on the Draft Report, p. 9.

4.7.2 Consultation on project specification report

Recommendation

The project specification report would be published in a timely manner. At the same time, the DNSP must notify parties on the Demand Side Engagement Register of the publication of the report.

Stakeholders would be provided with a minimum of four months to provide submissions on each project specification report.

Reasoning for recommendation

The MCE terms of reference requested that 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 consultation on project specification reports is to encourage ongoing engagement between DNSPs and non-network providers, and the consideration of non-network alternatives as part of DNSPs' daily planning practices.

The Draft Report had proposed including an opportunity for accelerated consultation on project specification reports, working in conjunction with the proposed Demand Side Engagement Strategy and DAPR. However, the majority of submissions on the Draft Report raised concerns about how to demonstrate compliance with the provisions in order to qualify for the accelerated consultation option.

In light of these comments and given that we have recommended an increase in the RIT-D threshold to $5 million, we consider that an appropriate balance would be removing the accelerated consultation process and setting the consultation period to four months (as opposed to six months). Although the RIT-T process allows for three months' consultation, we consider that non-network providers would require an additional month as distribution investments may attract more non-network options than in transmission investments. Also we consider that having one consultation process would simplify the overall process.

Classifying non-network options as credible options

We recommend that under the project assessment process, the absence of a non-network proponent in itself should 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 provider is identified with the non-network option, the DNSP would still be required to consider the non-network option under the project assessment process as long as the option is commercially and technically feasible and can be implemented in sufficient time to meet the need.

4.8 Project Assessment Process – Consideration of Market Benefits and Costs

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 regarding each credible option. It is proposed that the market benefits would 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. The costs would 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 would be measurable as a benefit or cost to relevant market participants.

Reasoning for recommendation

Our 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.

In its submission, the Victorian Department of Primary Industries (DPI) stressed the importance of facilitating embedded generation on the network and the need to capture all the associated benefits. It submitted that the list of market benefits should be amended to include any benefits from network augmentation which may contribute to increases in embedded generation (either through reducing average costs of connection or improving the embedded generator's ability to input energy to the grid).[78]

We agree with DPI on the increasing importance of facilitating embedded generation and consider that the list of market benefits would permit such types of benefits to be included in the assessment. The proposed list includes any changes to parties' costs caused by the potential investment and, any changes in load transfer capacity and the potential for load transfer capacity of embedded generation. Also, as part of their annual reports, DNSPs would provide forecasts on the level of embedded generation and information on their activities with respect to embedded generation.

4.9 Publication of draft and final project assessment reports

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.

78 DPI, Submission on the Draft Report, p. 2.

For proposed investments which do not meet the requirements of the STT and where the estimated capital cost of the preferred 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.

DNSPs would be required to consult publicly 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 report, 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 option, after taking into account, where relevant, the submissions received on the draft project assessment report.

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

Reasoning for recommendation

The objective of the preparation and publication of 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 stakeholders with an opportunity to raise any concerns regarding DNSPs' assessments of credible options before DNSPs finalise their preferred option. The proposed minimum 30 business days 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.

Giving DNSPs the option of publishing their final project assessment report in their DAPR (if the cost is less than $20 million) will decrease the compliance costs for DNSPs, while ensuring that DNSPs publish final project assessment reports for large investments as soon as practicable.

4.10 RIT-D and the AER determination process

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 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 process.

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

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 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.

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 that the test can be amended in response to market developments 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 would 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.

Giving the AER the option of publishing the RIT-D, RIT-D guidelines, RIT-T, and RIT-T guidelines in a single document is appropriate. 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, the AER should be given 12 months after the making of the Rules to make and publish the RIT-D and associated guidelines.

5 Dispute Resolution Process

This Chapter describes the proposed new dispute resolution process for distribution planning (a diagram outlining the proposed design is provided in Appendix E.2). In considering the appropriate design, we have used the dispute resolution process developed for the RIT-T as the basis.

<u>**Summary of recommendations**</u>

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

19. The process would apply to a DNSP's application of the RIT-D against the requirements in the Rules and cover all stages and decisions made by DNSPs when applying the RIT-D. It would be a compliance review only.

20. Registered Participants, the AEMO, the AEMC, Connection Applicants, Intending Participants, interested parties and non-network providers would be able to raise a dispute under the proposed process.

21. The deadline for raising a dispute 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 that contains the relevant final project assessment report.

22. The AER would either reject the dispute or make a determination on the dispute within 40-100 business days of receiving the dispute notice, depending on the complexity of the dispute. The AER could make a determination to direct the DNSP to amend its final project assessment report only if:[79]

    - 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

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

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[79] The maximum period for the AER to consider and make determinations on disputes has been corrected to 100 business days (as opposed to 60 business days).

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 apply to disputes related to the RIT-D process under the national framework and the MCE has requested that the national framework includes a separate dispute resolution process.

The purpose of the separate dispute resolution process for the national framework is to provide an accessible, certain and timely mechanism for stakeholders to question DNSPs' decision making and, in doing so, improve the transparency of DNSPs' decisions and apply a regulatory discipline on their behaviour. The process would 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. It is noted that disputes raised under this process would be excluded from the dispute resolution process under Chapter 8 of the Rules.

5.2 Addressing the Principles for the Review

In developing our recommendations for the dispute resolution process requirements in this Chapter, we have taken into consideration the following principles for the Review.

Economic Efficiency:

The recommendations for the dispute resolution process support the principle of economic efficiency by:

- limiting the types of parties that can raise a dispute to Registered Participants, the AEMO, the AEMC, Connection Applicants, Intending Participants, interested parties and non-network providers; and
- providing the AER with an opportunity to dismiss disputes which are invalid, misconceived or lacking in substance.

Transparency:

The recommendations for the dispute resolution process achieve the principle of transparency by:

- providing an accessible and timely mechanism for stakeholders to question DNSPs' decision making and, in doing so, making DNSPs' decisions transparent and applying a regulatory discipline on their behaviour; and
- requiring the AER to publish its reasons for making a determination.

Proportionality:

The recommendations for the dispute resolution process achieve the principle of proportionality by limiting the scope of the dispute resolution process to the application of the RIT-D. This balances 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.

Technological Neutrality:

The recommendations for the dispute resolution process achieve the principle of technological neutrality by expanding the current dispute resolution arrangements to also be available to interested parties, non-network providers, the AEMC, the AEMO, Connection Applicants and Intending Participants in addition to Registered Participants.

Consistency across the NEM:

The recommendations for the dispute resolution process achieve the principle of consistency across the NEM by:

- including all investments subject to the RIT-D to be within the scope of a common dispute resolution process; and

- making the proposed process for the consideration of disputes and the grounds on which the AER is able to request DNSPs to amend their final project assessment reports, consistent with the dispute process for the RIT-T.

Consistency with Transmission Planning Framework:

The recommendations for the dispute resolution process achieve the principle of consistency with the transmission planning framework by limiting the dispute resolution process to a review of DNSPs' compliance, which is a similar approach to the scope of the dispute resolution process for RIT-T.

5.3 Scope of the Dispute Resolution Process

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 DNSPs' compliance with the Rules regarding 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;

- 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 could 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 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.

It is not appropriate to extend the dispute resolution process to DNSPs' annual planning processes and reports as these 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

We recommend that the process 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 RIT-T.

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%.[80]

The RIT-D process 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 any market benefits should be quantified; and
- which options were credible options.

[80] See clause 5.6.2(i) of the National Electricity Rules.

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 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. This recommendation is also consistent with the RIT-T, where all projects that are assessed under the RIT-T are also subject to the dispute resolution process.

5.4 Process for Raising a Dispute

Recommendation

Registered Participants, the AEMC, the AEMO, Connection Applicants, Intending Participants, interested parties and non-network providers would 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 the relevant final project assessment report.

Reasoning for 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 cannot be resolved informally among the relevant parties.

Under the current arrangements, dispute resolution is only available to Registered Participants. Therefore, non-network providers and interested parties which are not Registered Participants are currently unable to raise disputes.

We previously proposed that Registered Participants, the AEMC, Connection Applicants, Intending Participants and interested parties should be the relevant types of parties to raise disputes. Submissions from DNSPs on the Draft Report were concerned with the potential for a large number of vexatious disputes if the types of parties raising a dispute were not limited to Registered Participants and non-network providers. DNSPs supported the inclusion of "non-network proponents".[81] On the other hand, TEC submitted that electricity consumers ultimately pay for investments and should be able to contest network investments, and that the AER

81 For example, see submissions on the Draft Report from: ENA, p. 32; Energex, p. 4 of Annex A; EnergyAustralia, p. 14; Ergon Energy, p. 20; Integral Energy, p. 8; Victorian distribution businesses joint submission, pp. 11-12.

would be able to exclude "trouble-making" complaints which would provide a sufficient filter.[82]

We consider that any party which may be impacted by DNSPs' decisions under the RIT-D, including any non-network providers and interested parties, should be able to raise a dispute with the AER. Therefore, the scope of parties who can raise a dispute should be expanded to include Connection Applicants, Intending Participants, interested parties and non-network providers, as well as Registered Participants. We also propose including the AEMC and the AEMO in this list for consistency with the RIT-T.

With respect to interested parties, we consider that the same definition used for the RIT-T dispute resolution process should apply. Hence for an interested party, the AER has to be of the opinion that it has the potential to suffer a material and adverse market impact from the preferred option. We consider that this would act as a safeguard against potential vexatious disputes. Additionally, the AER would be required to reject any dispute if the AER considers that the grounds for the dispute were invalid, misconceived or lacking in substance. We consider that this would sufficiently address concerns from DNSPs about trivial disputes whilst also being consistent with the RIT-T.

In addition to interested parties, we also consider that there is a further need to permit any provider of a non-network alternative to also raise disputes. We suggest that non-network providers be defined as "parties who provide non-network solutions as an alternative to network augmentation, including embedded generation or demand side options". The recommended safeguard would be sufficient to exclude any invalid or misconceived complaints to ensure that unnecessary resources are not spent defending otherwise legitimate decisions.

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 cannot 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 stakeholders 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.

82 See TEC, Submission on the Draft Report, p. 10.

5.5 AER's Powers in Considering Disputes

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 the 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.

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 by an additional 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 Rules; or

- there was a manifest error in the calculations performed by the DNSP in applying the RIT-D.

Reasoning for 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.

Timing for dispute resolution

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 100 business days, would provide certainty to DNSPs regarding the timing of their investments.

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6 Review into distribution reliability standards and other issues

This Review has considered the annual planning, project assessment and reporting processes. As stated in the Draft Report, there are other aspects to the regulatory regime which influence how distribution businesses plan, invest and operate their networks. These areas relate mainly to the determination and application of the security and reliability standards, the reporting of network reliability and asset management practices.

We suggest that a separate review is initiated by the MCE into the security and reliability standards relating to the design and planning of distribution networks. The objective of this review is to assess whether there would be benefits from incorporating certain aspects of these arrangements into a consistent national framework.

There is a lack of consistency and transparency in how the different jurisdictional standards are determined and described. Also, how the distribution businesses interpret and comply with these standards can vary significantly across the NEM. These factors may impact adversely on the efficiency and timeliness of network investments and operations, and on the reliability of distribution services. They may also undermine market participants' understanding of, and expectations regarding, network reliability and security performance, reducing their capacity to make efficient location decisions.

These variations also make it difficult for non-network providers to operate on a NEM wide basis as they have to be familiar with the different methods used to express, deliver and report reliability standards. Furthermore, if the form of the standards are not economically derived (such that they would not consider customer value of reliability), efficient provision of reliability may not occur and the prospects for including demand side participation diminish.

Some market participants interpreted the Draft Report as recommending harmonisation of the existing jurisdictional security and reliability obligations. We want to be clear that this is not the intention. It is appropriate for the standards to differ across jurisdictions as the performance of networks, and their applicable standards, are directly attributable to the network characteristics and the resources which are invested. The purpose of the review is to assess the benefits of having a common overarching framework for expressing and applying the standards which would allow for local conditions.

The rationale and possible scope for such a review is discussed in this Chapter and a draft terms of reference is contained in Appendix B.

6.1 Reasons and Scope for the Review

The security of supply and reliability standards, set out in jurisdictional instruments, underpin how the network planning, investment and operation processes are currently undertaken by the DNSPs. The SKM Background Report details the various reliability criteria and standards applicable in each jurisdiction and shows that a mixture of deterministic and probabilistic criteria are applied.[83] 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.

How the security and reliability standards are applied in the DNSPs planning, investment and operating processes will affect the objectives of a national framework for electricity distribution network planning and performance. The existing variations in the processes for determining the reliability planning standards that apply in each jurisdiction can make it difficult for businesses to operate on a NEM wide basis. Also, the different forms and specification of jurisdictional reliability standards may make it difficult for market participants to understand and forecast network performance.

Developing a consistent national framework for how reliability planning standards are determined and specified in each jurisdiction could deliver more efficient investment and facilitate increased demand side participation. Also, increasing the availability of information on network standards may encourage open discussion about their appropriateness and the requirements to meet the standards.

For these reasons, we consider that a review into the current arrangements for distribution planning standards is warranted with a view to:

- delivering net benefits to the market in the form of efficient provision of reliability by promoting more efficient and timely network investment, and improving network operation and performance;
- strengthening the accountability of DNSPs for cost-effective achievement of the reliability and security standards; and
- improving the transparency of network reliability and security performance to users of network services, providers of non-network alternatives and final energy consumers.

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.[84] That review considered issues relating to transmission planning and advised that increased transparency and a nationally consistent approach would bring benefits to the market. That Review also recommended that the form of any standards be based upon sound economic considerations in order to promote economic efficiency. We consider that a review into the framework in distribution standards is now required.

[83] SKM Background Report, op cit.

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

Any review should recognise the existing regulatory treatments in balancing reliability and costs to consumers and the existing differences in the determination, form and application of security and reliability standards across the jurisdictions. Instead, we see the rationale for the review in looking at the transparency and form of the standards and assessing whether the market would benefit from having a consistent framework on how jurisdictional standards are expressed and applied.

The issues we suggest that need to be assessed are set out below.

6.1.1 Arrangements for determining and expressing jurisdictional reliability standards

A number of issues arise from the current arrangements that may affect the efficiency of the markets which the review should assess:

- 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 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 are also responsible 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.

6.1.2 The form and derivation of the standards

The development of planning standards, that are derived from economic considerations (such that they would consider customer value of reliability) and which strike a reasonable balance between distribution system costs and customer reliability, can promote economic efficiency. By aligning the design and operation of the network with the value of reliability, economic standards could provide a more efficient balance between delivered reliability outcomes and the costs users are prepared to pay to receive them. This could support the level of reliability in the market and promote efficient capital investment across networks and demand side response.

In our Draft Report for the Demand Side Participation Review, we recognised that in some jurisdictions the form of the current standards are not derived from economic considerations. We consider that requiring all planning standards to be economically derived may also improve the prospects for the inclusion of demand side participation.

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

In relation to Schedule 5.1 of the Rules, we suggest that there are three possible issues that the review should address:

- 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;
- 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. The relevance of the Schedule to distribution needs to be assessed; and
- there is a need for the Schedule 5.1 standards to complement and support the jurisdictional standards.

6.2 Other Issues

6.2.1 Asset Management Practices

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.[85]

Asset management practices work in conjunction 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 significant differences in the reporting requirements relating to businesses' asset management practices. 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 a 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. A best practice criteria would assist to achieve a minimum level of consistency across the NEM.

Common reporting requirements for asset management would also deliver significant benefits. 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.

Submissions from the DNSPs noted that while the establishment of a minimum best practice criteria would enforce a least common denominator approach on the DNSPs,

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

it should not be a matter for the Rules to prescribe such criteria given that the incentive based regulatory regime is intended to provide the right incentives to manage their assets efficiently. ENA noted that while some harmonisation of the existing jurisdictional arrangements may be desirable, the first step needs to be agreement and commitment by the jurisdictions to harmonise the existing reporting requirements.[86]

We continue to consider that there could be benefits from including the asset management practices into the national framework for distribution planning. However, given the significant changes needed to implement the recommendations set out in this Final Report, we consider that this issue could be explored at a later date.

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 use customer reliability and customer service standards for 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 the Service Target Performance Incentive Scheme (STPIS). [87]

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 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;

86 ENA, Submission on the Draft Report, p.38.

87 AER, Electricity Distribution Network Service Providers Service Target Performance Incentive Scheme, Final Decision, June 2008, (amended in May 2009).

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

- 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 Energy (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 of other strategies, such as live line working and using mobile generators.

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). With respect 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 outdated 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 recommend that a more consistent approach be 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 continued pursuit in this area and greater consistency across the NEM.