Australian Energy Market Commission

RULE CHANGE

DRAFT RULE DETERMINATION

National Electricity Amendment (Distribution Network Planning and Expansion Framework) Rule 2012

Rule Proponent
Ministerial Council on Energy

Commissioners
Pierce
Spalding

14 June 2012

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About the AEMC

The Council of Australian Governments, through its Ministerial Council on Energy (MCE), established the Australian Energy Market Commission (AEMC) in July 2005. The AEMC has two principal functions. We make and amend the national electricity and gas rules, and we conduct independent reviews of the energy markets for the MCE.

Summary

The Commission has made a draft rule determination to establish a national framework for distribution network planning and expansion which would be applicable to distribution businesses in each National Electricity Market (NEM) jurisdiction. This national framework consists of an annual planning and reporting process (including a number of demand side engagement obligations on distribution businesses), and a regulatory investment test for distribution (RIT-D) process.

The Commission considers that the draft rule will contribute to the achievement of the national electricity objective (NEO) by establishing a clearly defined and efficient planning process for distribution network investment. This will support the efficient development of distribution networks. The draft rule will also provide transparency to, and information on, distribution business planning activities and decision making processes. This will assist market participants in making efficient investment decisions and enable non-network providers to put forward credible non-network options as alternatives to network investment.

In making its draft determination, the Commission has considered whether the proposed framework will provide for the minimisation of total system costs which should, over time, lead to efficient prices and higher quality and service for consumers. The Commission considers that the draft rule will achieve this outcome.

The draft rule has been made in response to a rule change request submitted by the Ministerial Council on Energy (MCE) on 30 March 2011.[1] The rule change request sought to implement (with some amendments) the recommendations put forward in the Australian Energy Market Commission's (AEMC's) Review of National Framework for Electricity Distribution Network Planning and Expansion which was completed in September 2009.

The Commission's draft determination

The Commission's draft determination is to make a more preferable rule. The draft rule is largely reflective of, and consistent with, the rule proposed by the MCE. However, it incorporates several policy modifications and a number of amendments to improve and clarify the application and operation of the new national framework.

A brief summary of the key components of the national framework is provided below.

Distribution annual planning process

Each distribution network service provider (DNSP) will be required to carry out an annual planning review covering a minimum forward planning period of five years. The planning review will apply to all distribution assets and activities undertaken by DNSPs that would be expected to have a material impact on the distribution network.

1 The MCE has since been replaced by the Standing Committee on Energy and Resources.

Distribution annual planning report

Each DNSP will be required to publish a distribution annual planning report (DAPR) by the date specified by the relevant jurisdictional government. The DAPR is intended to provide transparency to the outcomes of DNSPs' annual planning review and update on outcomes since the previous DAPR. Specifically, the DAPR will include information on:

- forecasts, including capacity and load forecasts, over the required planning period at the sub-transmission and zone substation level and, where they have been identified, for overloaded primary distribution feeders;
- system limitations, which may include limitations resulting from forecast load exceeding total capacity, the need for asset refurbishment or the need to improve system security;
- projects that have been (or will be) assessed under the RIT-D;
- other committed projects with a capital cost of $2 million or greater that were urgent and unforseen or replacement and refurbishment projects; and
- other information including: a description of the network, regional development plans, outcomes from joint planning undertaken with other network service providers, performance standards and compliance against these standards, activities and actions taken to promote non-network initiatives (including embedded generation) and information on any significant investments in metering services.

Demand side engagement obligations

Each DNSP will be required to develop a demand side engagement strategy. The strategy, which is to be documented and published, will detail a DNSP's processes and procedures for assessing non-network options as alternatives to network expenditure and interacting with non-network providers. DNSPs will also be required to establish and maintain a register of parties interested in being notified of developments relating to distribution network planning and expansion.

Joint planning arrangements

DNSPs will be required to meet on a regular basis with the owners of any connected networks to undertake joint planning where there are issues affecting multiple networks.

In addition, relevant network service providers will be required to carry out the requirements of the existing regulatory investment test for transmission (RIT-T) where at least one of the options to address a network issue includes a transmission component with an estimated capital cost greater than $5 million.

Regulatory investment test for distribution

The RIT-D, which will replace the current regulatory test, establishes the processes and criteria to be applied by DNSPs in order to identify investment options which best address the needs of the network. The RIT-D will be applicable in circumstances where a network problem exists and the estimated capital cost of the most expensive potential credible option to address the identified need is more than $5 million. Certain types of projects and expenditure will be exempt from assessment under the RIT-D, including projects initiated to address urgent and unforeseen network issues and projects related to the replacement and refurbishment of existing assets.

The RIT-D rules require the AER to develop and publish the RIT-D test in accordance with the principles set out in the rules.[2] The RIT-D rules also include the procedural consultation requirements to be followed by DNSPs when applying the test.

The RIT-D will require DNSPs to assess the costs and benefits of each credible investment option to address a specific network problem to identify the option that maximises net market benefits (or minimises costs where the investment is required to meet reliability standards). The key features of the RIT-D project assessment process include:

- screening for non-network options: DNSPs may bypass the requirement to prepare and publish a non-network options report where a DNSP has reasonable grounds to determine that a non-network option will not be a credible option;
- publication of a non-network options report: where applicable, DNSPs will be required to prepare and publish a non-network options report ahead of carrying out the RIT-D project assessment. The recommended period for consultation is four months; and
- RIT-D project assessment: to determine the preferred investment option, DNSPs will be required to quantify all applicable costs for each investment option, but will have the option of quantifying applicable market benefits.[3]

Dispute resolution process

The draft rule also includes a dispute resolution process that would be open to all projects subject to the RIT-D. Relevant parties would be able to raise disputes with the Australian Energy Regulator (AER) in relation to a DNSP's application of the RIT-D against the rules. The AER may then either reject a dispute, or make a determination on the dispute (the timeframes for doing so will depend on the complexity of the dispute).

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2 The RIT-D rules also require the AER to develop and publish RIT-D application guidelines. These guidelines are intended to provide supplementary information to support distribution businesses in applying the test.

3 See Figure 9.1 for an illustrative summary of the RIT-D process.

The AER may only make a determination which directs a DNSP to amend its final project assessment report where the DNSP:

- has not correctly applied the RIT-D in accordance with the rules; or
- has made a manifest error in its calculations.

In making a determination on a dispute, the AER would specify the timeframe for the DNSP to amend the final project assessment report.[4]

Implementation and transition

It is intended that the existing jurisdictional arrangements for annual planning, annual reporting and project assessment will be rolled back to the extent that they are covered by the final rule (where the Commission determines that a final rule is to be made). To allow sufficient time for this transition, the Commission has identified 1 January 2013 as a possible date for commencement of a rule.

In recognition that implementation of a final rule would result in changes to DNSPs' and other market participants' operational practices, the draft rule provides the following key transitional arrangements:

- DNSPs will be provided with a minimum period of six months after the rule commences before being required to publish their first DAPR;
- DNSPs will be provided with a maximum period of nine months after the rule commences within which to publish their first demand side engagement document and establish the demand side engagement register; and
- the AER will be provided with a period of nine months after the rule commences to develop and publish the RIT-D and RIT-D application guidelines.[5]

Reasons for the Commission's draft determination

The Commission is satisfied that the draft rule will, or is likely to, contribute to the achievement of the NEO. Moreover, the Commission is satisfied that the draft rule is likely to better contribute to the achievement of the NEO than the proposed rule. The Commission considers that the draft rule promotes efficient outcomes by:

- creating incentives for, and a framework within which, DNSPs can explore non-network options as alternatives to capital expenditure and for non-network providers to efficiently plan and offer alternative, more cost effective options to network augmentations (thereby promoting efficient investment in distribution networks);
- ensuring that DNSPs have a clearly defined and efficient planning process to allow them to identify and address potential problems on the network in a timely

4 See Figure 10.1 for an illustrative summary of the dispute resolution process.

5 See Figure 11.1 for a summary of the implementation and transition timeframes.

manner (thereby promoting efficient operation of, and investment in, distribution networks); and

- ensuring that network users have the best information available in order to be able to plan where best to connect to the network (thereby promoting efficient use of electricity services).

Invitation for submissions and final rule determination

The Commission invites written submissions on this draft rule determination, including the draft rule, by 9 August 2012. The Commission will consider submissions on the draft rule determination and publish its final rule determination by 20 September 2012.

Contents

1 MCE's rule change request

1.1 The rule change request

On 30 March 2011, the Ministerial Council on Energy (MCE) (proponent) submitted a rule change request to the Australian Energy Market Commission (AEMC or Commission) to facilitate the introduction of a new national framework for electricity distribution network planning and expansion (rule change request) which would be applicable to distribution businesses in each National Electricity Market (NEM) jurisdiction.[6]

The rule change request seeks to implement the rule change recommendations made by the AEMC in its final report for the Review of National Framework for Electricity Distribution Network Planning and Expansion (the Review) (Final Report). It should be noted that the MCE's rule change request included several modifications to the recommendations set out in the Final Report.

1.2 Rationale for rule change request

The regulatory arrangements governing distribution network planning are contained in Chapter 5 of the National Electricity Rules (NER or 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 options. The objective of this rule change request is to implement a national framework for distribution network planning and expansion which addresses these issues.

1.3 Solution proposed in the rule change request

The MCE's rule change request concludes a significant and extensive policy development phase, as outlined in the section 1.4 below. The proposed rule sets out a national framework for distribution network planning and expansion that includes:

- a distribution annual planning review;
- a distribution annual planning report (DAPR);

6 Throughout this draft rule determination, reference to 'national framework' means the national rules proposed to replace the separate rules that have to date operated in each jurisdiction and which would be applicable to distribution businesses in each NEM jurisdiction.

- a demand side engagement strategy;
- joint planning arrangements;
- the regulatory investment test for distribution (RIT-D); and
- a dispute resolution process.

The key elements of the proposed rule are described further in chapters 5 to 11.

1.4 Relevant background

The 2006 amended Australian Energy Market Agreement (AEMA) sets out a number of energy market regulatory functions currently carried out by jurisdictions that the Council of Australian Governments (COAG) agreed would be transferred to a national framework.[7] In respect of electricity distribution, these included connections and capital contribution requirements, distribution network expansion and distributor interface with customers and embedded generators.

In 2007, the MCE Standing Committee of Officials (MCE SCO) commissioned a report by NERA Economic Consulting (NERA) and Allen Consulting Group (ACG) to provide advice on a national framework for electricity distribution network planning, connections and capital contribution arrangements. The NERA and ACG Report, *Network Planning and Connection Arrangements – National Framework for Distribution Networks*, was published in August 2007.[8]

In its December 2008 policy response to the NERA and ACG Report, the MCE indicated that a national framework for electricity distribution connection arrangements, and electricity distribution connection charge and capital contribution arrangements, would be progressed as part of the same legislative package as the National Energy Customer Framework (NECF).[9]

In respect of a national framework for distribution planning and expansion, the MCE considered that, given a number of recent developments in the NEM,[10] further consultation and analysis was required before details of arrangements governing planning and expansion of electricity distribution networks could be finalised. In light of the AEMC having recently completed a similar review of transmission

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7 See Annexure 2 of the 2006 amended AEMA for a summary of the relevant retail and distribution functions which governments agreed would be transferred to a national framework.

8 See: www.mce.gov.au.

9 The NECF refers to a national arrangement designed to govern the sale and supply of electricity and natural gas to retail customers. The customer framework was initially expected to apply in some states and territories from 1 July 2012 although there is currently some uncertainty in respect of the application dates.

10 Namely the development of a regulatory investment test for transmission (RIT-T), the proposed introduction of a Carbon Pollution Reduction Scheme (CPRS) and increased Renewable Energy Target (RET), and the AEMC's review of Demand Side Participation in the NEM.

arrangements, the MCE considered it was appropriate for the AEMC to progress this work.

In December 2008, the MCE directed the AEMC to conduct a review into the arrangements for electricity distribution planning and expansion in the NEM and propose recommendations to assist the establishment of a national framework for such planning and expansion.

The AEMC submitted its Final Report to the MCE on 23 September 2009. The Final Report provided the AEMC's recommendations and supporting reasoning for the establishment of a national framework. It included a proposed rule to implement the new arrangements for consideration by the MCE.

The AEMC's recommended design for a national distribution planning framework consisted of three key components:

- an annual planning and reporting process;
- a demand side engagement strategy; and
- the RIT-D process.

The AEMC considered that it was through the interaction of these three components that the intended purpose and objectives of the national framework would best be achieved.[11]

In September 2010, the MCE provided its response to the recommendations set out in the Final Report. Overall, the MCE expressed support for the AEMC's findings and recommendations.[12]

Subsequently, on 30 March 2011, the MCE lodged a rule change request, including a proposed rule, to the AEMC. The MCE requested that the AEMC progress the rule change request having regard to the contents of the MCE's response.

1.5 Commencement of rule making process

On 29 September 2011, the Commission published a notice under s. 95 of the National Electricity Law (NEL) advising of its intention to commence the rule making process and the first round of consultation in respect of the rule change request. A consultation paper prepared by AEMC staff identifying specific issues or questions for consultation was also published with the rule change request. Submissions closed on 24 November 2011.

11 AEMC 2009, *Review of National Framework for Electricity Distribution Network Planning and Expansion*, Final Report, 23 September 2009, Sydney, p. vii.

12 Ministerial Council on Energy 2010, *Review of National Framework for Electricity Distribution Network Planning and Expansion: Response to the Australian Energy Market Commission's Final Report*, September 2010.

The Commission received sixteen submissions and three supplementary submissions on the rule change request as part of the first round of consultation. They are available on the AEMC website. Summaries of the policy and legal issues raised in submissions and the Commission's response to each issue are contained in Appendices A and B respectively.

1.6 Extension of time

The timing for publication of the draft rule determination was extended under s. 107 of the NEL on three occasions. On 29 September 2011, the Commission published a notice under s. 107 of the NEL extending the period for publishing the draft rule determination to 22 March 2012. On 9 February 2012, a further notice was published extending the time period to 26 April 2012. On both occasions, the Commission considered that the rule change request raised issues of sufficient complexity and difficulty such that additional time was necessary.

On 5 April 2012, the Commission published a third notice extending the time period to 14 June 2012. In this instance, consultation with stakeholders resulted in a number of supplementary submissions to the Consultation Paper. These supplementary submissions included a number of alternative solutions to address several of the key issues identified. To ensure these submissions were given due consideration, the Commission extended the period of time for making the draft rule determination until mid-June.

1.7 AEMC reviews and rule changes

The AEMC is currently undertaking a number of other review and rule change processes which may be of interest to stakeholders engaged with this rule change request. These are:

- ERC0142: Distribution Losses in Expenditure Forecasts (proposed by the Copper Development Centre (CDC)).
- ERC0134: Economic Regulation of Network Service Providers (proposed by the Australian Energy Regulator (AER) and Energy Users Rule Change Committee (EURCC)).
- EPR0027: Review of distribution reliability outcomes and standards.
- EPR0022: Power of Choice - Stage 3 DSP Review.
- EPR0019: Transmission Frameworks Review.

Further information on the AEMC's reviews and rule changes can be found on the AEMC website at www.aemc.gov.au.

1.8 Consultation on draft rule determination

In accordance with the notice published under s. 99 of the NEL, the Commission invites submissions on this draft rule determination, including the draft rule, by 9 August 2012.

In accordance with s. 101(1a) of the NEL, any person or body may request that the Commission hold a hearing in relation to the draft rule determination. Any request for a hearing must be made in writing and must be received by the Commission no later than 21 June 2012.

Submissions and requests for a hearing should quote project number 'ERC0131' and may be lodged online at www.aemc.gov.au or by mail to:

Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

2 Draft rule determination

2.1 Commission's draft determination

In accordance with s. 99 of the NEL, the Commission has made this draft rule determination in relation to the rule proposed by the MCE.

The Commission has determined not to make the proposed rule but rather to make a more preferable rule.[13] The draft rule is largely reflective of, and consistent with, the proposed rule.

The Commission's reasons for making this draft rule determination are set out in section 2.4.

A draft of the more preferable rule (draft rule) is attached to and published with this draft rule determination. The key features of each element of the draft rule are described in chapters 5 to 11.

2.2 Commission's considerations

In assessing the rule change request, the Commission considered:

- its powers under the NEL to make the draft rule determination;
- the rule change request;
- the MCE's policy response to the AEMC's Final Report;
- submissions and supplementary submissions received during first round consultation; and
- the ways in which the proposed rule will, or is likely to, contribute to the achievement of the national electricity objective (NEO).

There is no relevant MCE Statement of Policy Principles relating to this rule change request.[14]

13 Under s. 91A of the NEL the AEMC may make a rule that is different (including materially different) from a market initiated proposed rule (a more preferable rule) if the AEMC is satisfied that having regard to the issue or issues that were raised by the market initiated proposed rule (to which the more preferable rule relates), the more preferable rule will or is likely to better contribute to the achievement of the NEO.

14 Under s. 33 of the NEL the AEMC must have regard to any relevant MCE statement of policy principles in making a rule.

2.3 Commission's power to make the rule

The Commission is satisfied that the draft rule falls within the subject matter about which the Commission may make rules as set out in s. 34 of the NEL and in Schedule 1 of the NEL. The draft rule is within:

- the matter set out in s. 34 (1)(a)(iii), as it relates to the activities of persons participating in the NEM or involved in the operation of the national electricity system; and
- the matters set out in items 11, 12, 14A and 14B of Schedule 1 to the NEL, as it relates to the operation of transmission and distribution systems which is subject to NER.

2.4 Rule making test

Under s. 88(1) of the NEL the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the NEO. This is the decision making framework that the Commission must apply.

The NEO is set out in s. 7 of the NEL as follows:

> "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."

For the rule change request, the Commission considers that the relevant aspects of the NEO are:[15]

- efficient investment in distribution networks;
- efficient operation of distribution networks; and
- efficient use of electricity services.

The Commission is satisfied that the draft rule will, or is likely to, contribute to the achievement of the NEO by providing clearly defined, nationally consistent arrangements which will promote more efficient outcomes than under current arrangements. This will promote the long term interests of consumers in respect of the price of electricity. The draft rule promotes efficiency in the following ways:

15 Under s. 88(2), for the purposes of s. 88(1) the AEMC may give such weight to any aspect of the NEO as it considers appropriate in all the circumstances, having regard to any relevant MCE statement of policy principles.

- by creating incentives for, and a framework within which, DNSPs can explore non-network options as alternatives to capital expenditure and for non-network providers to efficiently plan and offer alternative, more cost effective options to network augmentations (thereby promoting efficient investment in distribution networks);

- by ensuring DNSPs have a clearly defined and efficient planning process to allow them to identify and address potential problems on the network in a timely manner (thereby promoting efficient operation of, and investment in, distribution networks); and

- by ensuring distribution network users have the best information available in order to be able to plan where best to connect to the network (thereby promoting efficient use of electricity services).

Under s. 91(8) of the NEL the Commission may only make a rule that has effect with respect to an adoptive jurisdiction if satisfied that the proposed rule is compatible with the proper performance of Australian Energy Market Operator (AEMO)'s declared network functions. The draft rule is compatible with AEMO's declared network functions because it clarifies the arrangements in respect of joint planning and therefore enhances AEMO's ability to perform its declared network functions.

2.5 More preferable rule

Under s. 91A of the NEL, the AEMC may make a rule that is different (including materially different) from a market initiated proposed rule (a more preferable rule) if the AEMC is satisfied that, having regard to the issues or issues that were raised by the market initiated proposed rule (to which the more preferable rule relates), the more preferable rule will, or is likely to, better contribute to the achievement of the NEO.

Having regard to the issues raised by the proposed rule, the Commission is satisfied that the draft rule will, or is likely to, better contribute to the achievement of the NEO than the proposed rule for the following reasons:

- the draft rule achieves a better balance between the regulatory burden on DNSPs in complying with the new national framework and the potential benefits to be gained from planning under a national regime, relative to the proposed rule. It does so by removing several obligations proposed to be imposed on DNSPs where the benefits of complying with the obligation would be unlikely to outweigh the costs of doing so;[16]

- the draft rule creates a more efficient planning process relative to the proposed rule by removing (or amending) several of the proposed obligations on the AER

16 For example, see the amendments made in respect of the DAPR public forum, DAPR certification, the demand side engagement database and the regulatory investment test to apply to joint planning projects.

where the intended purpose of the obligation is already (or could be better) achieved by other, more efficient means;[17] and

- the draft rule should improve the application and operation of the national framework by making a number of amendments to the drafting of the proposed rule to remove any ambiguity and improve the clarity of the rule.[18]

2.6 Other requirements under the NEL

In applying the rule making test in s. 88 of the NEL, the Commission has also considered whether there are any relevant MCE statements of policy principles as required under s. 33 of the NEL. There is no MCE statement of policy principles which is relevant to this rule change.

The Commission considers that the following sections of the NEL are also not relevant to the draft rule:

- s. 88A (specifying the circumstances in which the AEMC must take into account form of regulation factors);
- s. 88B (specifying the circumstances in which the AEMC must take into account revenue and pricing principles); and
- s. 89 (relating to the matters to which the AEMC must have regard when making jurisdictional derogations).

17 For example, see the amendments made in respect of exemptions to the DAPR reporting requirements, exemptions to the dispute resolution process and the review of DNSPs' consideration of non-network options.

18 For example, see the amendments made in respect of the RIT-D cost threshold, the RIT-D specification threshold test, transition from the regulatory test to the RIT-D and other more minor drafting amendments.

3 Commission's reasons

The Commission has analysed the rule change request and assessed the issues that it raises. For the reasons set out below and in the following chapters, the Commission has determined to make a draft rule.

3.1 Assessment of the issues

A key assumption in assessing this rule change request is that the existence of different regulatory arrangements (that are not justified by differences in local circumstances) for electricity distribution network planning and expansion constitutes an impediment to the development of a truly national energy market. This is likely to result in potentially significant costs being imposed on market participants, with those costs typically being passed on to end users.

The Commission considers that streamlining and improving the quality of the distribution planning frameworks can be expected to lower the cost and complexity of regulation. This would be particularly relevant to investors and market participants seeking to operate across jurisdictions. In addition, a national approach could enhance regulatory certainty and lower barriers to competition.

In addition and consistent with the conclusions of the AEMC's Review, the Commission considers that the existence of a robust planning and expansion framework for monopoly distribution networks is likely to facilitate sound and transparent decision making.

Given the objectives of the 2006 amended AEMA and the conclusions of the AEMC's Review, this rule change request represents the next stage in the development and implementation of a national framework for electricity distribution network planning and expansion.

In this context, the Commission has not assessed whether or not a national planning framework is needed. Rather, it has assessed whether the proposed design of the national framework as proposed in the rule change request is appropriate and will, or is likely to, contribute to the achievement of the NEO.

3.2 Assessment of the proposed rule

The Commission's draft rule largely adopts the MCE's proposed rule subject to several policy modifications and amendments to improve the clarity and application of the rule.

These policy modifications and amendments are set out in detail with supporting reasoning in chapters 5 to 11. In summary, the key amendments made to the proposed rule include:

- removal of the requirement for DNSPs to conduct a public forum on the content of the DAPR;
- removal of the requirement for DAPRs to be certified by the Chief Executive Officer (CEO), and a Director or Company Secretary of the DNSP;
- removal of the ability for the AER to grant exemptions or variations to the annual reporting requirements;
- removal of the requirement for DNSPs to establish, maintain and publish a database of non-network proposals and/or case studies of non-network proposals as part of the proposed demand side engagement strategy;
- amendments to the regulatory investment test to clarify its application to investments identified through joint planning;
- amendments to the proposed specification threshold test (STT) (renamed the non-network options report);
- clarification in relation to the re-application of the RIT-D in certain circumstances;
- removal of specific review and audit powers for the AER in relation to DNSPs' consideration of non-network options;
- removal of the ability for the AER to grant exemptions from the dispute resolution process; and
- clarification in relation to the transition from the regulatory test to the RIT-D.

3.3 Proposed changes to the structure of Chapter 5 of the NER

In addition to the changes noted above, the draft rule includes changes to the broader structure of Chapter 5 of the NER in order to more clearly distinguish between the connection arrangements (now in Chapter 5 Part A) and the planning arrangements (now in Chapter 5 Part B). These changes are structural only and do not affect the rationale of, nor the intent behind, any rules not directly related to, or affected by, this rule change request.

The Commission considers that the separation of the connection and planning arrangements currently set out in Chapter 5 into clearly defined sections will simplify the rules and improve their accessibility to, and usability by, market participants and interested parties.

In addition, a discrete section of the rules for connections may help to facilitate any later review of the connection arrangements which may be proposed as an outcome of

the Transmission Frameworks Review (TFR), without the need to unsettle the new distribution planning rules.[19]

Table 3.1 provides a summary of Chapter 5 Part B as restructured by the draft rule, including references to equivalent clauses in the current rules and the MCE's proposed rule.

Table 3.1 Structure of new Part B Network Planning and Expansion

Draft rule reference	Content of clause	Current NER reference	Proposed rule reference
Clause 5.10.2	Local definitions used in Part B	n/a	Chapter 10
Clause 5.11.1	Obligations regarding forecasts for connection points to the transmission network	Clause 5.6.1	Clause 5.6.1
Clause 5.11.2	Obligations of NSPs for planning connections to the network	Clause 5.6.2	Clause 5.6.2
Clause 5.12	Planning and reporting obligations for TNSPs	Clause 5.6.2A	Clause 5.6.2A
Clause 5.13	Planning and reporting obligations for DNSPs	n/a	Clause 5.6.2AA
Clause 5.14	Joint planning obligations of NSPs	Clause 5.6.2	Clause 5.6.2, 5.6.2AA
Clause 5.15	Regulatory investment tests generally	Clauses 5.6.5D, 5.6.5E	Clauses 5.6.5D, 5.6.5E
Clause 5.16	Regulatory investment test for transmission	Clauses 5.6.5B, 5.6.5C, 5.6.6, 5.6.6A, 5.6.6AA	Clauses 5.6.5B, 5.6.5C, 5.6.6, 5.6.6A, 5.6.6AA
Clause 5.17	Regulatory investment test for distribution	n/a	Clauses 5.6.5CA, 5.6.5CB, 5.6.6AB, 5.6.6AC
Clause 5.18	Construction of funded augmentations	Clause 5.6.6B	Clause 5.6.6B
Clause 5.19	Scale Efficient Network Extensions	Clause 5.5A	Clause 5.5A

19 In chapter 12 of the TFR First Interim Report, the Commission indicated that amendments to the NER Chapter 5 connection arrangements are required to clarify their interpretation and application. It noted that this clarification should proceed regardless of whether some of the more significant potential reforms relevant to connections discussed in chapters 13 and 14 of that report are progressed. For further information see: AEMC 2011, *Transmission Frameworks Review, First Interim Report*, 17 November 2011, Sydney, pp. 155-169.

Clause 5.20	AEMO's National Transmission Planning responsibilities	Clause 5.6A	Clause 5.6A
Clause 5.21	AEMO's obligations to publish information and guidelines, and provide advice regarding network development	Clause 5.6.3	Clause 5.6.3
Clause 5.22	AEMC's last resort planning powers	Clause 5.6.4	Clause 5.6.4

3.4 AEMC review of the national framework

The proposed rule included a requirement for the AEMC to conduct a review of the national framework three years after the date the rule commenced.[20] It was intended that this review would assess the effectiveness of the provisions and to identify any potential areas for further improvement.

The Commission has not included this provision in the draft rule on the basis that there are already established processes under which such a review can be undertaken by the AEMC if required.[21] The existing provisions under the NEL allow for flexibility in the nature and content of any such review if undertaken. The Commission therefore does not consider it appropriate to limit this flexibility by including a rule in the NER requiring the AEMC to undertake a review of the national framework within a specified timeframe.

3.5 Civil penalty provisions

The provisions of the NER which are classified as civil penalty provisions are listed in the National Electricity (South Australia) Regulations. The Commission may amend or remove these provisions but must notify the MCE of the policy rationale for taking this course of action.

The draft rule removes a number of provisions which are currently classified as civil penalty provisions. In addition, the draft rule amends certain provisions which are currently classified as civil penalty provisions. The civil penalty provisions which are amended or removed are set out in Table 3.2.

While the Commission cannot create new civil penalty provisions, it may recommend to the MCE that new or existing provisions of the NER be classified as a civil penalty provisions. The new provisions which the Commission is proposing to recommend to the MCE be classified as civil penalty provisions are set out in Table 3.3.

The Commission considers that the new and amended provisions should be classified as civil penalty provisions because breach of these provisions would pose a risk to the

20 Proposed clause 5.6.2AA(b).

21 See s. 41 of the NEL which provides for the MCE to direct the AEMC to review any matter relating to a market for electricity. Also see s. 45 of the NEL which provides for the AEMC to conduct a review into the operation and effectiveness of the rules or any matter relating to the rules.

secure operation of the NEM. In addition, the classification of these provisions as civil penalties would encourage compliance by relevant parties with these provisions.[22]

In its submission to the consultation paper, the AER noted that a major challenge currently presented to it in monitoring and enforcing compliance with the current network planning provisions is the lack of enforcement tools available to it.[23] Specifically, the AER noted that none of the requirements regarding the need to undertake a regulatory investment test for transmission (RIT-T) and the associated consultation requirements were listed as civil penalty provisions under the National Electricity Regulations. The implication of this is that the only formal action the AER could take in relation to a suspected breach of these provisions would be to seek an order from the Federal Court. The AER considered that the effectiveness of the network planning framework may be further improved if the obligations were classified as civil penalty provisions.

At this stage, the Commission has not proposed to recommend to the MCE that any provisions related to the RIT-T or the RIT-D be classified as civil penalty provisions under the National Electricity (South Australia) Regulations. While classification of these provisions as civil penalty provisions may encourage compliance with these provisions, the Commission does not consider that a breach of these rules would pose a direct risk to the secure operation of the NEM. However, the Commission invites stakeholders' views on this matter in submissions to this draft rule determination.

22 These provisions would only become civil penalty provisions if the relevant amendments to the National Electricity (South Australia) Regulations were made and come into effect.

23 AER, Consultation Paper submission, pp. 7-8.

Table 3.2 Existing civil penalty provisions

Current clause reference	Draft clause reference	Proposed recommendation to the MCE	Reason for recommendation
Clause 5.6.2(a)	Draft clause 5.12.1(a)	Retain as civil penalty provision	Renumbered (with no amendments).
Clause 5.6.2(b)	Draft clause 5.12.1(b)	Retain as civil penalty provision	Renumbered with minor amendments: reference to DNSPs removed. Clause remains consistent with original intent.
Clause 5.6.2(e)	Draft clause 5.11.2(a)	Retain as civil penalty provisions	Restructured and renumbered with minor amendments: original clause split into three separate clauses with minor changes made to the terminology used to accommodate new definitions. Clause remains consistent with original intent.
	Draft clause 5.11.2(b)		
	Draft clause 5.11.2(c)		
Clause 5.6.2(e1)	n/a	Remove	Clause deleted by draft rule.
Clause 5.6.2(e2)	n/a	Remove	Clause deleted by draft rule.
Clause 5.6.2(f)	n/a	Remove	Clause deleted by draft rule.
Clause 5.6.2(g)	n/a	Remove	Clause deleted by draft rule.
Clause 5.6.2(g1)	n/a	Remove	Clause deleted by draft rule.
Clause 5.6.2(h)	n/a	Remove	Clause deleted by draft rule.
Clause 5.6.2(k)	n/a	Remove	Clause deleted by draft rule.
Clause 5.6.2(m)	Draft clause 5.4AA(a)	Retain as civil penalty provision	Renumbered (with no amendments).
Clause 5.6.2(n)	Draft clause 5.2.6	Retain as civil penalty provision	Renumbered (with no amendments).
Clause 5.6.4(l)	Draft clause 5.22(k)	Retain as civil penalty provision	Renumbered (with no amendments).

Table 3.3 Proposed civil penalty provisions

Proposed clause reference	Draft clause reference	Proposed recommendation to the MCE	Reason for recommendation
Proposed clause 5.6.2(b1)	Draft clause 5.14.1(a)(2)	Classify as new civil penalty provision	Obligation on TNSPs to conduct joint planning with DNSPs. Equivalent clause to draft clause 5.14.1(a)(1) which is also recommended as a civil penalty provision.
Proposed clause 5.6.2AA(d)	Draft clause 5.13.2(a)	Classify as new civil penalty provision	Obligation on DNSPs to analyse expected future operation of the network. Equivalent clause to clause 5.6.2(a) which is listed as a civil penalty provision.
Proposed clause 5.6.2AA(g)	Draft clause 5.13.2(e)	Classify as new civil penalty provision	Obligations on DNSPs in conducting the distribution annual planning review.
Proposed clause 5.6.2AA(h)	Draft clause 5.14.1(a)(1)	Classify as new civil penalty provisions	Obligation on DNSPs to conduct joint planning with TNSPs. Equivalent clause to draft clause 5.14.1(a)(2) which is also recommended as a civil penalty provision.
	Draft clause 5.14.1(d)	Classify as new civil penalty provisions	Obligations on DNSPs and TNSPs in conducting joint planning.

4 Commission's assessment approach

This chapter describes the Commission's approach to assessing the rule change request in accordance with the requirements set out in the NEL (and explained in chapter 2).

In assessing the rule change request, the Commission has given particular consideration to the likely impacts of the proposed rule on the following aspects of the NEO:

- *efficient investment in distribution networks*, including incentives for DNSPs to explore non-network options as alternatives to capital expenditure and for non-network providers to efficiently plan and offer alternative, more cost effective options to network augmentations;

- *efficient operation of network*s, for example, by ensuring DNSPs have a clearly defined and efficient planning process to allow them to identify and address potential problems on the network in a timely manner; and

- *efficient use of electricity services*, for example, by ensuring network users have the best information available in order to be able to plan where best to connect to the network.

To assist in its assessment, the Commission has considered each element of the proposed national framework against the following criteria:

- *transparency* - whether the proposed rule would require DNSPs to make available sufficient information to enable network users to make efficient decisions and non-network providers to propose feasible and credible alternatives to address network problems;

- *proportionality* – whether the costs arising from the processes and regulatory requirements under the proposed rule are proportionate to the benefits. The extent of information provided and the consultation processes must strike the appropriate balance; and

- *harmonisation of jurisdictional requirements* – whether the proposed rule provides for differences in operating environments and network conditions across DNSPs while recognising that maintaining consistency across the NEM is a key objective of the rule change request.

Economically efficient outcomes will be achieved where the frameworks in the rules provide for the minimisation of total system costs. This should, over time, lead to efficient prices and higher quality and service for consumers. In assessing this rule change request, the Commission has therefore also considered the extent to which the proposed rule avoids creating bias towards any particular technology, including towards network solutions where non-network options are available.

The effects of the rule change request on these criteria have been compared with the status quo. In this case, the status quo includes existing jurisdictional arrangements as well as the provisions currently contained in Chapter 5 of the NER.

5 Distribution annual planning review

This chapter sets out the Commission's views in relation to the distribution annual planning review, having regard to the views of stakeholders in submissions to the consultation paper. This chapter is structured as follows:

- section 5.1 describes the distribution annual planning review as proposed by the proponent and summarises stakeholder responses to the consultation paper on this matter;
- section 5.2 sets out the Commission's proposed amendments to the proposed rule and a description of the draft rule on this matter;
- section 5.3 provides a summary of the Commission's analysis and assessment of the distribution annual planning review draft rules; and
- based on the Commission's assessment in section 5.3, section 5.4 sets out the Commission's conclusions on this matter.

5.1 Proposed rule

5.1.1 Description of the proposed rule

The proposed rule for the distribution annual planning review consists of a number of key elements as follows:

- Each DNSP would be required to undertake an annual planning process covering a minimum forward planning period of five years for their distribution assets (and ten years for dual function assets[24]).
- The forward planning period would commence one day after the 'jurisdiction specified date'.[25]
- 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 in the forward planning period.
- In carrying out the planning process, DNSPs would, at a minimum, be required to:
  - prepare forecasts of maximum demands for the relevant network assets;

24 The NER defines dual function assets as any part of a network owned, operated or controlled by a DNSP which operates between 66 kV and 220 kV and which operates in parallel, and provides support, to the higher voltage transmission network which is deemed by clause 6.24.2(a) of the rules to be a dual function asset.

25 This date is prescribed by regulation under the application Act of a participating jurisdiction.

- identify (based on those forecasts) system limitations; and
- take into account non-network options when considering investment options.

Included within the proposed arrangements for the distribution annual planning review are discrete proposals for a distribution annual planning report, a demand side engagement strategy and joint planning. These components of the annual planning process are dealt with separately in chapters 6, 7 and 8 respectively.

Currently, the NER contains a high level obligation on DNSPs to analyse the expected future operation of the distribution network over a minimum five year period.[26] This obligation, although applicable to all NEM jurisdictions, is vague and in most cases is supplemented by jurisdictional arrangements which differ across jurisdictions in respect of rigour and transparency.[27] The proponent intended that the proposed rule would replace these current arrangements and streamline the obligations into a single national framework.

5.1.2 Proponent's view

In the rule change request, the proponent stated that the purpose of having a national annual planning process was to ensure that all DNSPs conduct a clearly defined, common and efficient planning process. Such a process would assist in maintaining a secure, reliable and safe supply of electricity for end users across the NEM. Further, the proponent considered that having clearly defined planning obligations would assist Transmission Network Service Providers (TNSPs), connection applicants and non-network providers to understand DNSPs' decision making processes and make more efficient investment decisions when participating in the market.

5.1.3 Stakeholder views

In submissions to the consultation paper, stakeholders were generally supportive of the proposed distribution annual planning review and process.

Start of the forward planning period

In response to a question posed in the consultation paper regarding the forward planning period, the majority of DNSPs supported the proposal to allow each jurisdiction to determine the start date of the forward planning period.[28] The Energy

26 NER clause 5.6.2(a).

27 For a comparison of jurisdictional planning and reporting requirements (as at July 2009), see AEMC 2009, *Review of National Framework for Electricity Distribution Network Planning and Expansion*, Draft Report, 7 July 2009, Sydney, Appendix D.

28 ENA, Consultation Paper submission, p. 5; Ergon Energy, Consultation Paper submission, p. 4; Energex, Consultation Paper submission, p. 1; Victorian DNSPs, Consultation Paper submission, p. 2; Aurora Energy, Consultation Paper submission, p. 2; Ausgrid, Consultation Paper submission, p. 3; Endeavour Energy, Consultation Paper submission, p. 1; ETSA Utilities,

Networks Association (ENA) and Victorian DNSPs[29] considered that aligning planning periods nationally would reduce the usefulness and relevancy of the published information and would not facilitate transparency.[30]

In contrast, the AER and EnerNOC expressed support for the implementation of a uniform start date for the forward planning period and publication of the DAPRs.[31] The AER considered this would improve transparency and consistency in industry practices and more effectively facilitate joint planning across jurisdictions and between transmission and distribution networks. In addition, EnerNOC considered a single start date would be beneficial given the possibility of projects that cover more than one jurisdiction.

Stakeholders were divided in their views on whether it was necessary to include a default start date for the forward planning period in the rules.[32] Ergon Energy considered that any default date should be subject to jurisdictional transitional arrangements to ensure DNSPs would not be unfairly subject to complying with both jurisdictional and new national reporting requirements.[33]

Treatment of dual function assets

Ausgrid and Endeavour Energy sought clarity on the treatment of dual function assets within the proposed annual planning arrangements.[34]

Ausgrid considered that the proposed national framework would create a number of anomalies in relation to the obligations of NSPs who are registered as a DNSP for their distribution assets and as a TNSP for their dual function assets.[35] It noted that the proposed rule would result in a DNSP who also owns and operates dual function assets (as a TNSP) being required to:

- conduct an annual planning review for its dual function assets as a TNSP rather than an integrated review of all assets, and consult with itself as a DNSP;
- carry out joint planning internally as a TNSP and DNSP; and
- prepare a transmission annual planning report in relation to dual function assets which are otherwise subject to the RIT-D. Due to the proposed timing

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Consultation Paper submission, p. 4; Essential Energy, Consultation Paper submission, p. 4; Origin, Consultation Paper submission, p. 1.

29 The Victorian distribution businesses are CitiPower and Powercor Australia, United Energy, SP AusNet and Jemena Electricity Networks.

30 ENA, Consultation Paper submission, p. 5; Victorian DNSPs, Consultation Paper submission, p. 2.

31 AER, Consultation Paper submission, p. 2; EnerNOC, Consultation Paper submission, p. 3.

32 The AER, Aurora Energy and EnerNOC were supportive of the proposal while Ergon Energy, the Victorian DNSPs, Endeavour Energy and Essential Energy did not support the proposal.

33 Ergon Energy, Consultation Paper submission, p. 7.

34 Endeavour Energy, Consultation Paper submission, pp. 1-2; Ausgrid, Consultation Paper submission, pp. 4-5.

35 Ausgrid, Consultation Paper submission, pp. 6-7.

requirements, Ausgrid also noted that it would not be possible for these separate reports to be published as a single document.

Ausgrid considered that the draft rule should provide for a more integrated process for DNSPs with dual function assets to review, plan and report on those assets in a way which is integrated into the process it carries as a DNSP.

Endeavour Energy requested that the final rule clearly articulate that dual function assets are to be treated as distribution assets for the purposes of planning and expansion under the rules.[36]

5.2 Application of the proposed rule and proposed modifications

The draft rule has largely adopted the proposed rules in relation to the arrangements for the distribution annual planning review as described above, subject to a number of amendments to improve and clarify the application of the rule. The manner and reasoning for these amendments are set out below.

5.2.1 Policy amendments

The Commission does not propose to make any material amendments to the requirements of the distribution annual planning review as set out in the proposed rule.

5.2.2 Amendments to improve clarity and application

The Commission has made a number of amendments to improve and clarify the application of the distribution annual planning review requirements in the proposed rule without affecting the principles underlying the proposed rule. These changes are as follows:

- *Purpose clause*: the draft rule omits a distribution annual planning review and report purpose clause.
- *Preparation of network level forecasts*: the draft rule does not require DNSPs to prepare forecasts at the network level.[37]
- *List of system limitations*: the draft rule clarifies that the list of factors which may cause a system limitation is non-exclusive.
- *Compliance with asset management policies*: the draft rule does not include an explicit requirement for DNSPs to comply with their asset management policies.[38]

36 Endeavour Energy, Consultation Paper submission, pp. 1-2.

37 Despite not being required to prepare these forecasts, DNSPs would not be prevented from doing so where they considered it appropriate.

- *Dual function assets*: the draft rule clarifies that DNSPs who are registered as TNSPs for the purposes of owning and operating dual function assets may publish the transmission annual planning report in the same document, and at the same time, as the distribution annual planning report.

- *Other minor changes*: to reflect comments made in submissions to the consultation paper, the draft rule includes a number of other minor drafting amendments. The policy issues log set out in Appendix A, and the legal issues log set out in Appendix B, provide further details of these amendments.

5.2.3 Description of the draft rule

Having regard to the amendments set out above, the key features of the distribution annual planning process draft rules are described below.

Box 5.1: Distribution annual planning review

Scope:

- A DNSP must:[39]
  - determine an appropriate forward planning period for its distribution assets;[40] and
  - analyse the expected future operation of its network over the forward planning period.
- The minimum forward planning period for the purposes of the distribution annual planning review is five years.[41]
- The distribution annual planning review must include all assets that would be expected to have a material impact on the DNSP's network over the appropriate forward planning period.[42]

Requirements:

- Each DNSP must, in respect of its network:

38 To the extent that such compliance is required by jurisdictional instruments, this obligation will be captured elsewhere in the draft rule.

39 Draft clause 5.13.2(a).

40 The forward planning period must commence one day after the "DAPR date" which is the date set out jurisdictional legislation by which a DNSP must publish its DAPR. This is discussed further in chapter 6.

41 Draft clause 5.13.2(b).

42 Draft clause 5.13.2(c).

- prepare forecasts covering the forward planning period of maximum demands for:[43]
  - sub-transmission lines;
  - zone substations; and
  - to the extent practicable, primary distribution feeders,

  having regard to:
  - the number of customer connections;
  - energy consumption; and
  - estimated total output of embedded generating units;
- identify, based on the outcomes of the forecasts, limitations on its network, including limitations caused by one or more of the following factors:[44]
  - forecast load exceeding total capacity;
  - the requirement for asset refurbishment or replacement;
  - the requirement for power system security or reliability improvement;
  - design fault levels being exceeded;
  - the requirement for voltage regulation; and
  - the requirement to meet any regulatory obligation or requirement;
- identify whether corrective action is required to address system limitations, and, if so, identify whether it is required to:[45]
  - carry out the requirements of the RIT-D; and
  - carry out the requisite demand side engagement obligations;
- take into account any jurisdictional electricity legislation.[46]

43 Draft clause 5.13.2(d)(1).

44 Draft clause 5.13.2(d)(2).

45 Draft clause 5.13.2(d)(3).

46 Draft clause 5.13.2(d)(4).

5.3 Commission's assessment

The Commission has analysed and assessed the policy and drafting issues arising from the rule change request in respect of the proposed distribution annual planning process. Outlined below is the Commission's assessment of this aspect of the draft rule, including the reasons why it considers this aspect of the draft rule meets the NEO.

5.3.1 Requirements and scope of the distribution annual planning review

Relative to current arrangements, the draft rule introduces greater prescription regarding the scope and requirements of the distribution annual planning process. The draft rule maintains the minimum five year forward planning horizon but clarifies that the planning process must encompass all assets owned, and activities undertaken, by each DNSP which may materially affect the performance of its distribution network.

The Commission considers that replacing the current arrangements with a comprehensive, clearly defined annual planning process will assist DNSPs in making efficient planning decisions by requiring them, over a reasonable period, to identify and address potential problems in respect of their networks.

In addition, the introduction of a process which is consistent across NEM jurisdictions should assist market participants and third parties in making better, more informed planning and investment decisions. This is because ensuring a common approach to distribution network planning will lower the cost and complexities associated with understanding DNSPs decision making processes. This is particularly relevant for investors and market participants seeking to operate across jurisdictions.

Start of the forward planning period

The consultation paper for this rule change request sought views from stakeholders on the implications of allowing each jurisdiction to determine the start of the forward planning period for DNSPs in that jurisdiction.[47] While the majority of DNSPs noted support for a jurisdiction specified start date[48], several other stakeholders considered there would be benefit in implementing a uniform start date applicable to all DNSPs[49].

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47 In its Distribution Network Planning and Expansion Review, the AEMC recommended that DNSPs be required to publish their DAPRs by 31 December each year, covering the forward planning period starting 1 January the following year. This recommendation was subsequently amended by the MCE in the rule change request to provide for each jurisdiction to determine the start date for the forward planning period by setting the date on which DNSPs must have published their DAPRs. The amendment was intended to allow for the planning process to reflect the seasonal variability of electricity demand in each jurisdiction.

48 ENA, Consultation Paper submission, p. 5; Ergon Energy, Consultation Paper submission, p. 4; Energex, Consultation Paper submission, p. 1; Victorian DNSPs, Consultation Paper submission, p. 2; Aurora Energy, Consultation Paper submission, p. 2; Ausgrid, Consultation Paper submission, p. 3; Endeavour Energy, Consultation Paper submission, p. 1; ETSA Utilities, Consultation Paper submission, p. 4; Essential Energy, Consultation Paper submission, p. 4; Origin, Consultation Paper submission, p. 1.

49 AER, Consultation Paper submission, p. 2; EnerNOC, Consultation Paper submission, p. 3.

The Commission recognises that requiring DNSPs to plan over the same forward planning period could lead to an improvement in comparability of information reported by DNSPs in their DAPRs. However, any move to a uniform forward planning period may result in a large, potentially disproportionate impact on those DNSPs who would subsequently be required to change planning practices. Furthermore, a key benefit from introducing nationally consistent annual reporting requirements is to improve transparency of DNSPs planning processes and activities. However, the differences in DNSPs forward planning periods are less important than ensuring consistency and transparency of the information being reported.[50] For this reason, the Commission supports each jurisdiction determining the start of the forward planning period for DNSPs in their jurisdiction (note that the draft rule requires that the forward planning period commence one day after the "DAPR date" which is the date set out under jurisdictional legislation by which a DNSP must publish its DAPR).

In the instance that a jurisdiction has not specified a DAPR date under jurisdictional legislation, the draft rule includes a default date which requires DNSPs to publish their DAPR by 31 December for the forward planning period beginning on 1 January. The Commission considers it is appropriate to specify a default date in the draft rule to avoid confusion in the instance a jurisdiction has not specified a DAPR date and to ensure DNSPs are clear in respect of their planning and reporting obligations. This matter is discussed further in chapter 6.

5.3.2 Treatment of dual functions assets

As noted above, Ausgrid and Endeavour Energy sought clarity on the treatment of dual function assets within the proposed annual planning arrangements.[51] The Commission notes that the anomalies identified by Ausgrid are a function of a broader issue in relation to the treatment of dual function assets in the NER. Specifically, while the rules require DNSPs who own and operate dual function assets to register as TNSPs by virtue of the definition of 'TNSP' in the rules, certain parts of the rules nonetheless treat dual function assets in the same way as distribution assets (as opposed to transmission assets).

While the Commission considers there may be merit in considering further whether the current arrangements in the rules for dual function assets are appropriate, it also considers that the issues around dual function assets are broader than the rules set out in Chapter 5 of the NER. Therefore, these issues may be better dealt with outside the scope of this rule change request.

Nevertheless, the proposed rule would benefit from further clarity in relation to the treatment of dual function assets and the obligations of NSPs who own and operate these assets. Therefore, while the Commission has not changed the current approach to the treatment of dual function assets in the context of network planning and expansion, this approach has been clarified by removing any ambiguity and providing for a more

50 The distribution annual reporting requirements are considered further in chapter 6.

51 Endeavour Energy, Consultation Paper submission, pp. 1-2; Ausgrid, Consultation Paper submission, pp. 4-5.

integrated approach, where possible, for NSPs that hold obligations both as owners of distribution assets and dual function assets.

At a high level, for the purposes of network annual planning and reporting, dual function assets will generally be treated in the same manner as transmission assets. In the context of project assessment, dual function assets will be treated in the same manner as distribution assets. In summary, the obligations on the owners and operators of dual function assets in relation to network planning and expansion are as follows:[52]

- *Annual planning review*: a DNSP with dual function assets will be required to conduct:
  - a transmission annual planning review for any dual function assets as a TNSP;[53] and
  - a distribution annual planning review for distribution assets as a DNSP.[54]
- *Annual planning report*: a DNSP with dual function assets will have the option of publishing a single distribution annual planning report by the relevant DAPR date. The content of the report is to include:
  - for dual function assets, the requirements of the transmission annual planning report (TAPR);[55] and
  - for distribution assets, the requirements of the DAPR.[56]
- *Joint planning arrangements for DNSP-TNSP*: an NSP with dual function assets:
  - in its capacity as a TNSP, will not be a TNSP for the purposes of carrying out joint planning under draft clause 5.14.1;[57] and
  - in its capacity as a DNSP, will be required to carry out joint planning in accordance with draft clause 5.14.1 in respect of its dual function assets and distribution assets with the TNSP of the transmission networks to which the DNSP's network is connected.[58]

52 A number of these obligations are discussed further in later chapters.

53 Draft clause 5.12.1.

54 Draft clause 5.13.2.

55 Draft clause 5.12.2.

56 Draft clause 5.13.3 and draft schedule 5.8.

57 Draft clause 5.14.1(c).

58 Draft clause 5.14.1(a)(1).

- *Project assessment process*: projects where a potential credible option to address an identified need includes expenditure on a dual function asset, will be subject to assessment under the RIT-D;[59]

- *Project assessment process for joint planning projects*: joint planning projects which include the possibility of expenditure on dual function assets will be subject to assessment under the RIT-T in all cases where at least one potential credible option to address an identified need contains a network or non-network option on a transmission network with an estimated capital cost greater than $5 million.[60]

5.4 Rule making test

The Commission is satisfied that the distribution annual planning arrangements as set out in the draft rule will, or are likely to, better contribute to the achievement of the NEO relative to the proposed rule. The draft rule is likely to promote efficient investment in, and efficient operation of, distribution networks for the long term interests of consumers in the following ways:

- ensuring DNSPs have a clearly defined and efficient planning process which allows them to identify and address potential problems on the network in a timely manner, thereby promoting efficient operation of the network; and

- providing a clearly defined and efficient planning process which includes a robust economic assessment which will help to ensure that DNSPs make efficient investment decisions in respect of their networks, thereby promoting efficient investment in the network.

59 Draft clause 5.17.3(b). See chapter 9 for further discussion on this matter.

60 Draft clause 5.14.1(d)(4). See chapter 8 for further discussion on this matter.

6 Distribution annual planning report

This chapter sets out the Commission's views in relation to the publication of a distribution annual planning report (DAPR) as part of the distribution annual planning process, having regard to the views of stakeholders in submissions to the consultation paper. This chapter is structured as follows:

- section 6.1 describes the DAPR as proposed by the proponent and summarises stakeholder responses to the consultation paper on this matter;
- section 6.2 sets out the Commission's proposed amendments to the proposed rule and a description of the draft rule;
- section 6.3 provides a summary of the Commission's analysis and assessment of the distribution annual planning report draft rules; and
- based on the Commission's assessment in section 6.3, section 6.4 sets out the Commission's conclusions on this matter.

6.1 Proposed rule

6.1.1 Description of the proposed rule

The proposed DAPR is designed to report on the outcomes of DNSPs' planning processes under the national framework. The proposed rule contains a number of key elements. These include requiring that the DAPR:

- be published by the applicable jurisdictional specified date each year;
- is certified by the Chief Executive Officer (CEO) and a Director or Company Secretary;
- includes forecasting information over the forward planning period, including capacity and load forecasts at the sub transmission and zone substation level, and, to the extent possible, primary distribution feeders;
- identifies system limitations which may include limitations resulting from forecast load exceeding total capacity, the need for asset refurbishment or the need to improve system security;
- reports on investments that have been (or will be) assessed under the RIT-D (including consultation undertaken in accordance with the demand side engagement strategy, estimated capital cost and impacts that may arise for connection and distribution use of system (DUOS) charges;
- provides details of all other committed projects with a capital cost of $2 million or greater that were 'urgent and unforseen' or replacements and refurbishment projects;

- reports on other information including:
  - 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.
- provides a summary of the DNSP's activities and actions to promote non-network initiatives, including embedded generation, and information on any significant investments in metering services.

The proposed rule also specifies that certain third parties (such as a registered participant, connection applicant, intending participant or a stakeholder registered on the demand side engagement register) would be able to request a public forum on the DAPR. The DNSP would be required to conduct the requested public forum within three months of the publication of the DAPR.

In addition, the proposed rule would allow the AER to grant exemptions from, or variations to, the annual reporting requirements where a DNSP can demonstrate in an application to the AER that, due to the DNSP's operational or network characteristics, the costs of preparing the data would manifestly exceed any benefit that may reasonably be obtained from reporting the relevant data.

Currently, the NER does not require DNSPs to publish the results of their planning activities with respect to distribution assets. However, the majority of jurisdictions have in place jurisdictional arrangements which require that each DNSP prepare an annual planning report.[61] While the jurisdictional reporting requirements tend to be similar in their objectives (that is, to report on emerging constraints on the distribution network), the scope, content and timeframes for reporting differ significantly across jurisdictions.

It is intended that the distribution annual reporting arrangements would replace the current jurisdictional reporting arrangements. With that said, it is noted that the proposed content of the DAPR would maintain the core of existing jurisdictional requirements.[62] The proposed rule provides flexibility for each jurisdiction to include additional planning and reporting requirements where it determines it appropriate.

61 The exception to this is the Australian Capital Territory (ACT).

62 AEMC 2009, *Review of National Framework for Electricity Distribution Network Planning and Expansion*, Final Report, 23 September 2009, Sydney, p. 29.

6.1.2 Proponent's view

The rule change request states that the purpose of the proposed national annual reporting requirements is to provide a more consistent and comprehensive annual reporting regime for DNSPs across the NEM. It claims that replacing the existing reporting and publication requirements with the requirements to prepare and publish a DAPR would provide transparency to DNSPs' decision making processes, thereby assisting non-network providers, TNSPs and connection applicants to make efficient investment decisions.

The proponent also stated that DAPRs could be used by regulators such as the AER to understand the activities undertaken by DNSPs and how they are developing their networks.

6.1.3 Stakeholder views

Exemptions or variations to the annual reporting requirements

Around half the submissions to the consultation paper expressed support for the proposal to allow the AER to grant exemptions or variations to the proposed annual reporting requirements.[63]

Essential Energy considered the proposal would provide a mechanism to balance the circumstances of a DNSP with jurisdictional requirements and would provide DNSPs with time to develop systems to comply with the national framework.[64] In addition, Ausgrid considered the rules should be flexible to reflect current planning processes unless there was a clear reason that current processes were inadequate.[65]

Ergon Energy considered, at the very least, exemptions should apply when requested during transitional periods.[66] Similarly, Endeavour Energy considered the ability to seek an exemption would be more efficient in situations where the application of jurisdictional requirements and the national framework lead to a duplication of processes.[67]

In contrast, several stakeholders did not support the proposal to allow exemptions or variations to the proposed annual reporting requirements.[68] The AER considered the

63 ENA, Consultation Paper submission, p. 8; Ergon Energy, Consultation Paper submission, p. 8; Energex, Consultation Paper submission, p. 3; Victorian DNSPs, Consultation Paper submission, p. 9; Endeavour Energy, Consultation Paper submission, pp. 4, 11; Essential Energy, Consultation Paper submission, p. 5; EnerNOC, Consultation Paper submission, p. 4; Ausgrid, Consultation Paper submission, p. 4; Essential Energy, Consultation Paper submission, p. 5.

64 Essential Energy, Consultation Paper submission, p. 5.

65 Ausgrid, Consultation Paper submission, p. 4.

66 Ergon Energy, Consultation Paper submission, p. 8.

67 Endeavour Energy, Consultation Paper submission, pp. 4, 11.

68 AER, Consultation Paper submission, p. 3; Origin, Consultation Paper submission, p. 1; AEMO, Consultation Paper submission, p. 1; Aurora Energy, Consultation Paper submission, p. 4.

information proposed for inclusion in the DAPR was essential information which, for the most part, should be considered by DNSPs in undertaking current planning activities. The AER considered that disclosure of this information would be unlikely to result in unwarranted additional cost or regulatory burden.[69] In addition, Aurora Energy considered that there should be no reason for exemptions from, or variations to, the annual reporting requirements unless the information was not available.[70]

Public forum on the content of the DAPR

In their joint submission, the Victorian DNSPs considered that the requirement to hold a public forum at the request of any member of the public may leave a DNSP open to vexatious claims.[71] Further, the Victorian DNSPs considered that public forums were not an effective or informative method for communicating highly technical details which require careful consideration of details and facts set out in the reports.[72]

Certification of the DAPR

Several stakeholders noted that they did not support the proposed DAPR certification requirements. The ENA and Victorian DNSPs considered that certification by the CEO and a Director or Company Secretary was inappropriately onerous.[73] As an alternative, these stakeholders suggested certification by the CEO or relevant general manager would be more appropriate. In addition, given the scope of the information reported in the DAPR, Essential Energy suggested sign off by an executive manager may be a better alternative.[74]

Stakeholders also expressed various views in relation to the information specified in schedule 5.8 proposed for inclusion in DNSPs DAPRs. Stakeholder views on this matter are also summarised in Appendix A.

6.2 Application of the proposed rule and proposed modifications

The draft rule has largely adopted the proposed rules in relation to the DAPR as described above, subject to several policy modifications and a number of amendments to improve and clarify the application of the rule. The manner and reasoning for these amendments are set out below.

6.2.1 Policy amendments

Having regard to the views of stakeholders, and having undertaken its own analysis and review, the Commission has, in the draft rule, made several modifications to the

69 AER, Consultation Paper submission, p. 3.

70 Aurora Energy, Consultation Paper submission, p. 4.

71 Victorian DNSPs, Consultation Paper submission, p. 4.

72 Victorian DNSPs, Consultation Paper submission, p .4.

73 ENA, Consultation Paper submission, p. 9; Victorian DNSPs, Consultation Paper submission, p. 3.

74 Essential Energy, Consultation Paper submission, pp. 5-6.

proposed rule to improve the application of the rule and better promote the NEO. These modifications are as follows:

- *Exemptions or variations to the annual reporting requirements*: the draft rule removes the ability for the AER to grant exemptions or variations to the annual reporting requirements as set out in draft schedule 5.8.

- *Public forum on the content of the DAPR*: the draft rule removes the obligation on DNSPs to conduct a public forum on their DAPRs if requested to do so by a relevant party. However, the draft rule includes a new obligation on DNSPs to provide a contact person who can field queries from any party on the content of the DAPR. The relevant contact details are to be included on the DNSPs website.

- *Certification of the DAPR*: the draft rule removes the obligation for DAPRs to be certified by the CEO and a Director or Company Secretary of the DNSP.

- *Default DAPR date*: where a DAPR date (previously the 'jurisdiction specified date') has not been specified by a jurisdiction, the draft rule requires a DNSP to publish its DAPR by 31 December for the forward planning period beginning 1 January.

6.2.2 Amendments to improve clarity and application

The Commission has made a number of amendments to improve and clarify the application of the distribution annual planning report requirements in the proposed rule without affecting the principles underlying the proposed rule. These changes are as follows:

- *Jurisdiction specified date*: the draft rule removes the definition of 'jurisdiction specified date' and includes a new definition of 'DAPR date'.

- *Transmission-distribution connection points*: the draft rule provides that a DNSP is not required to include information in relation to transmission-distribution connection points in its DAPR if it is required to do so under jurisdictional electricity legislation;[75]

- *Load forecasts at the network level*: the draft rule removes the requirement for DNSPs to include in their DAPRs load forecasts for the network as a whole.

- *Forecasts of reliability targets*: the draft rule clarifies that DNSPs must provide information on their forecasted performance against the reliability targets in the service target performance incentive scheme.

75 'Transmission-distribution connection point' is defined in the draft rule as "the agreed point of supply established between a transmission network and a distribution network. See draft clause 5.10.2 (local definitions).

- *References to best estimates*: the draft rule removes references to 'best' estimates and clarifies that DNSPs will only be required, where applicable, to provide 'estimates' of the specified information.

- *Regional development plans*: the draft rule removes the requirement for DNSPs to identify on their regional development plans: (1) a summary of the forecast capacity and the relevant reliability targets for each region; and (2) other information as required by the relevant jurisdiction that applies to the DNSP.[76]

- *Transmission Annual Planning Report*: the 'annual planning report' has been renamed in the draft rule to refer to 'transmission annual planning report'.

- *Other minor changes*: to reflect comments made in submissions to the consultation paper, the draft rule includes a number of other minor drafting amendments. The policy issues log set out in Appendix A, and the legal issues log set out in Appendix B, provide further details of these amendments.

6.2.3 Description of the draft rule

Having regard to the amendments set out above, the key features of the distribution annual planning report draft rules are described below.

Box 6.1: Distribution annual planning report

Requirements:

- By the DAPR date each year, a DNSP must publish the DAPR setting out the results of the distribution annual planning review for the forward planning period beginning one day after the DAPR date.[77]

- A DNSP must include the information specified in schedule 5.8 of the NER in its DAPR.[78]

- A DNSP is not required to include in its DAPR information required in relation to transmission-distribution connection points if it is required to do so under jurisdictional electricity legislation.[79]

- As soon as practicable after it publishes a DAPR, a DNSP must publish on its website the contact details for a suitably qualified staff member of the DNSP to whom enquiries on the contents of the report may be directed.[80]

76 However, DNSPs are not prevented from including this information on their map(s) if they wish to do so.

77 Draft clause 5.13.3(b).

78 Draft clause 5.13.3(c).

79 Draft clause 5.13.3(d).

80 Draft clause 5.13.3(e).

- DAPR date means:
  - the date by which a DNSP is required to publish a DAPR under jurisdictional electricity legislation; or
  - if no such date is specified in jurisdictional electricity legislation, 31 December.[81]

Reporting requirements:

The following information must be included in a DNSP's DAPR:[82]

General information:

- information regarding the DNSP and its network, including:
  - a description of its network;[83]
  - a description of its operating environment;[84]
  - the number and types of its distribution assets;[85]
  - methodologies used in preparing the DAPR, including methodologies used to identify system limitations and any assumptions applied;[86] and
  - analysis and explanation of any aspects of forecasts and information provided in the DAPR that have changed significantly from previous forecasts and information in the preceding year.[87]

Forecast information:

- forecasts for the forward planning period, including at least:
  - a description of the forecasting methodology used, sources of input information and the assumptions applied;[88]
  - load forecasts for:[89]

81 Draft clause 5.13.3(a).

82 Draft schedule 5.8.

83 Draft schedule 5.8(a)(1).

84 Draft schedule 5.8(a)(2).

85 Draft schedule 5.8(a)(3).

86 Draft schedule 5.8(a)(4).

87 Draft schedule 5.8(a)(5).

88 Draft schedule 5.8(b)(1).

89 Draft schedule 5.8(b)(2).

- transmission-distribution connection points;
- sub-transmission lines;
- zone substations,

including (where applicable):

- total capacity;
- firm delivery capacity for summer periods and winter periods;
- peak load (summer or winter and the number of hours per year that 95 per cent of peak is expected to be reached);
- power factor at time of peak load;
- load transfer capacities; and
- generation capacity of embedded generating units;

— forecasts of future sub-transmission lines, transmission-distribution connection points and zone substations, including for the latter two asset categories:[90]

- location;
- future loading level; and
- proposed commissioning time (estimate of month and year);

— forecasts of the DNSP's performance against any reliability targets in a service performance target incentive scheme;[91]

— forecasts of any factors that may have a material impact on its network, including factors affecting:[92]

- fault levels;
- voltage levels;
- other power system security requirements; and
- ageing and potentially unreliable assets.

90 Draft schedule 5.8(b)(3).

91 Draft schedule 5.8(b)(4).

92 Draft schedule 5.8(b)(5).

Information on system limitations:

- information on system limitations for sub-transmission lines and zone substations, including at least:
  - estimates of the location and timing (month and year) of the system limitation;[93]
  - analysis of any potential for load transfer capacity between supply points that may decrease the impact of the system limitation or defer the requirement for investment;[94]
  - impact of the system limitation, if any, on the capacity at transmission-distribution connection points;[95]
  - discussion of the potential solutions that may address the system limitation in the forward planning period, if a solution is required;[96] and
  - where an estimated reduction in forecast load would defer a forecast system limitation for a period of at least 12 months, include:[97]
    - an estimate of the month and year in which the system limitation is 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 to defer the forecast system limitation;

Information on investments:

- a summary of each RIT-D project for which the RIT-D has been completed in the preceding year or is in progress, including:
  - a summary of the outcomes or progress of the RIT-D including any consultation undertaken in accordance with the demand side engagement document or any other consultation on the RIT-D project;[98]

93 Draft schedule 5.8(c)(1).

94 Draft schedule 5.8(c)(2).

95 Draft schedule 5.8(c)(3).

96 Draft schedule 5.8(c)(4).

97 Draft schedule 5.8(c)(5).

98 Draft schedule 5.8(e)(1).

- a description of the identified need for the investment;[99]
- a summary of each credible option assessed or being assessed (to the extent reasonably practicable);[100]
- if the RIT-D has been completed:[101]
  - identification of the preferred option;
  - a summary of the results of the net present value analysis of each credible option;
  - the estimated capital cost of the preferred option;
  - the estimated construction timetable and commissioning date (where relevant) of the preferred option; and
- any impacts on network users, including any potential material impacts on connection charges and DUOS charges that have been estimated;[102]

- for each identified system limitation which will require a RIT-D, provide an estimate of the month and year when the test is expected to commence;[103]
- for all committed investments to be carried out within the forward planning period with an estimated capital cost of $2 million or more (as varied by a cost threshold determination) that are to address a refurbishment or replacement need, or an urgent and unforseen network issue, provide:
  - the purpose of the investment;[104]
  - a brief description of the investment, including its location;[105]
  - the estimated capital cost of the investment; and[106]
  - an estimate of the date (month and year) the investment is expected to become operational;[107]

99 Draft schedule 5.8(e)(2).
100 Draft schedule 5.8(e)(3).
101 Draft schedule 5.8(e)(4).
102 Draft schedule 5.8(e)(5).
103 Draft schedule 5.8(f).
104 Draft schedule 5.8(g)(1).
105 Draft schedule 5.8(g)(2).
106 Draft schedule 5.8(g)(3).
107 Draft schedule 5.8(g)(4).

- a description of the alternative options considered by the DNSP in deciding on the preferred investment, including an explanation of the ranking of these options to the committed project. Alternative options could include, but are not limited to, generation options, demand side options, and options involving other distribution or transmission networks;[108]

Other information:

- information on any joint planning undertaken with a TNSP in the preceding year, including:
  - a summary of the process and methodology used by the DNSP and relevant TNSPs to undertake joint planning;[109]
  - any planned investments that have been discussed through this process, including estimated capital costs and estimated timing (month and year) of the investment;[110] and
  - where additional information on the investments may be obtained;[111]
- information on any joint planning undertaken with other DNSPs in the preceding year, including:
  - a summary of the process and methodology used by the DNSPs to undertake joint planning;[112]
  - any planned investments that have been discussed through this process, including estimated capital costs and estimated timing (month and year) of the investment;[113] and
  - where additional information on the investments may be obtained.[114]
- information on the performance of the DNSP's network, including a summary description of the:
  - reliability standards that apply, including the relevant codes, standards and guidelines;[115]

108 Draft schedule 5.8(g)(5).

109 Draft schedule 5.8(h)(1).

110 Draft schedule 5.8(h)(2).

111 Draft schedule 5.8(h)(3).

112 Draft schedule 5.8(I)(1).

113 Draft schedule 5.8(I)(2).

114 Draft schedule 5.8(I)(3).

115 Draft schedule 5.8(j)(1).

- quality of supply standards that apply, including the relevant codes, standards and guidelines;[116]
- performance of the distribution network against the reliability and quality of supply standards for the preceding year;[117]
- qualitative assessment of how the DNSP has complied with the applicable standards, its processes to ensure compliance, and a description of any areas of the standards that were not met in the preceding year and the corrective action taken;[118] and
- information in the most recent submission to the AER under the service target performance incentive scheme.[119]

- information on the DNSP's asset management approach, including:
  - a summary of any asset management strategy employed by the DNSP;[120]
  - a summary of any issues that may impact on the system limitations identified in the DAPR Report that has been identified through carrying out asset management;[121] and
  - information about where further information on the asset management strategy and methodology adopted by the DNSP may be obtained.[122]

- information on the DNSP's demand management activities, including a qualitative summary of:
  - non-network options that have been considered in the past year, including generation from embedded generating units;[123]
  - actions taken to promote non-network proposals in the preceding year, including generation from embedded generating units;[124] and
  - the DNSP's plans for demand management and generation from embedded generating units over the forward planning period;[125]

116 Draft schedule 5.8(j)(2).

117 Draft schedule 5.8(j)(3).

118 Draft schedule 5.8(j)(4).

119 Draft schedule 5.8(j)(5).

120 Draft schedule 5.8(k)(1).

121 Draft schedule 5.8(k)(2).

122 Draft schedule 5.8(k)(3).

123 Draft schedule 5.8(l)(1).

124 Draft schedule 5.8(l)(2).

- information on the DNSP's investments in metering or information technology systems which occurred in the preceding year, and planned investments in metering or information technology systems in the forward planning period;[126] and
- a regional development plan consisting of a map of the DNSP's network as a whole (or maps by regions in accordance with the DNSP's planning methodology or as required under any regulatory obligation or requirement), identifying:
  - sub-transmission lines, zone substations and transmission-distribution connection points;[127] and
  - any system limitations that have been forecast to occur in the forward planning period, including, where they have been identified, overloaded primary distribution feeders;[128]

Information on primary distribution feeders:

- for any primary distribution feeder identified by the DNSP that:[129]
  - in the first year of the forward planning period, is forecast to experience an overload; or
  - in the next two years, is forecast to exceed 100 per cent of its normal cyclic rating (in summer periods or winter periods) under normal operating conditions,

  the DNSP must set out:
  - the location of the primary distribution feeder;[130]
  - the extent of the overload in the first year of the forward planning period;[131]
  - the forecast load in the following two years and the extent the forecast load would exceed the normal cyclic rating (in summer periods or winter periods);[132]

125 Draft schedule 5.8(l)(3).

126 Draft schedule 5.8(m).

127 Draft schedule 5.8(n)(1).

128 Draft schedule 5.8(n)(2).

129 Draft schedule 5.8(d)(1)-(2).

130 Draft schedule 5.8(d)(3).

131 Draft schedule 5.8(d)(4).

132 Draft schedule 5.8(d)(5).

- any technically feasible options being considered by the DNSP to address the overload or forecast load that exceeds the normal cyclic rating;[133] and
- where an estimated reduction in forecast load would defer a forecast overload for a period of 12 months, include:[134]
  - estimate of the month and year in which the overload is forecast to occur;
  - a summary of the location of relevant connection points at which the estimated reduction in forecast load would defer the overload; and
  - the estimated reduction in forecast load in MW needed to defer the forecast system limitation.

6.3 Commission's assessment

The Commission has analysed and assessed the policy and drafting issues arising from the rule change request in respect of the proposed distribution annual planning report. Outlined below is the Commission's assessment, including the reasons why it considers this aspect of the draft rule better meets the NEO then the proposed rule.

6.3.1 Contents of the distribution annual planning report

The draft rule, through the reporting requirements set out in schedule 5.8, provides a consistent and comprehensive annual reporting regime for DNSPs across the NEM. The draft rule will improve the level of transparency of DNSPs' planning processes and activities. In doing so, the draft rule is likely to assist network users in making better informed and more efficient investment decisions. For example, customers and other parties would be able to use information contained within the DAPRs to identify and assess the most efficient location for establishing a new connection, having regard to possible upstream impacts and the possibility of requiring an upstream augmentation. In addition, non-network providers would be provided with information on possible investment opportunities allowing them to efficiently plan and potentially offer more cost effective solutions to network investment.

In addition, by improving the level of information available to the market, the draft rule should help to reduce information asymmetries between the AER and DNSPs, thereby assisting the AER in its five year revenue determination processes.

Finally, the Commission notes that the introduction of nationally consistent arrangements should lower the cost and complexities associated with understanding

133 Draft schedule 5.8(d)(6).

134 Draft schedule 5.8(d)(7).

DNSPs decision making processes, particularly for investors and market participants seeking to operate across jurisdictions. This should promote efficient decision making by market participants, and hence promote efficient investment in electricity services.

Exemptions or variations to the annual reporting requirements

The proposed rule empowered the AER to grant exemptions or variations to the annual reporting requirements where a DNSP was able to demonstrate to the AER that, due to its operational or network characteristics, the costs of preparing the data would manifestly exceed any benefit that may be reasonably obtained from reporting that data in a national regime. The proponent considered that this requirement was necessary to balance the cost to a DNSP of preparing the DAPR with the benefits to stakeholders from reporting.

While the Commission recognises that, in some circumstances, it may be appropriate for the rules to provide some flexibility to cater for differences in local circumstances, it does not consider that the inclusion of a broad exemption clause is the best means of providing flexibility in this instance. Rather, the Commission's preference is to focus on ensuring that the reporting requirements set out within schedule 5.8 are appropriate and fit for purpose for all DNSPs in the first instance.[135]

With that said, the Commission considers that the information proposed for publication in the DAPR is relevant information, which provides an appropriate level of detail to balance the potential benefits of providing the market with this information, and the potential costs of preparing the reports.

For this reason, the draft rule does not provide for the AER to grant exemptions or variations to the proposed annual reporting requirements as set out in proposed schedule 5.8.

Some stakeholders considered the ability to apply for an exemption or variation to the reporting requirements may be appropriate during transition to the national framework.[136] On this matter, the Commission's preference is to focus on ensuring that appropriate transitional provisions are in place to assist in the move to the national framework. Appropriately designed transitional provisions (which balance the need to provide DNSPs with an appropriate transitional period and the need to ensure the national framework is established and operational in a timely manner) would negate the need to provide for exemptions or variations to the reporting requirements.

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135 The Commission notes that where a specific requirement is unlikely to prove workable for a particular DNSP, it may be necessary to consider providing some flexibility within the rules, where appropriate. The Commission would be interested in feedback from stakeholders on whether any of the reporting requirements set out in draft schedule 5.8 are likely to be particularly problematic, and the reasons why.

136 Essential Energy, Consultation Paper submission, p. 5; Ausgrid, Consultation Paper submission, p. 4.

6.3.2 Publication of the distribution annual planning report

The draft rule requires DNSPs to publish their DAPRs on their website either by the date specified by the relevant jurisdiction, or where no such date is specified, by 31 December of each year. The Commission considers this obligation is a cost effective means of improving the transparency and accessibility of the information contained in the reports. Making this information publicly available in a timely manner is likely to assist network users (including non-network proponents) to make more informed and efficient investment decisions. In addition, by ensuring that network users have timely access to the most recent information available, the draft rule will assist network users in planning where best to connect to the network, thereby promoting efficient use of electricity services.

Annual publication of DNSPs planning activities in the DAPRs should also assist the AER in performing its regulatory activities by providing easily accessible information on a more frequent basis than is currently the case under the five year regulatory control period.

Public forum on the content of the DAPR

The proposed rule required DNSPs to conduct a public forum on their DAPRs within three months of the report being published each year, if requested to do so by a relevant party.[137] This requirement was intended to increase the opportunity for stakeholders to understand the information contained in the DAPR, through direct engagement with DNSPs.

While the Commission supports the intent of this proposal, it nonetheless agrees with the views of several stakeholders who considered that a public forum was not necessarily the most effective way of communicating to third parties, given the type of information proposed to be included in the DAPRs.[138]

For this reason, this obligation is not included in the draft rule. It is replaced by a new obligation which requires DNSPs to provide on their website the details of a relevant contact person who can field queries from any party on the content of the DAPR. In contrast to the proposed rule, this obligation provides a more cost effective means of providing an avenue for discussion on the relevant parts of the DAPR, to increase stakeholders understanding of the contents of the DAPR, without being onerous on DNSPs.

Certification of the DAPR

The proposed rule included a requirement that DAPRs be certified by the CEO, and a Director or Company Secretary. This requirement was intended to ensure that the reports met the necessary regulatory requirements and accurately represented the

137 A relevant party being a registered participant, connection applicant, intending participant or a stakeholder registered on the DNSPs demand side engagement register.

138 Victorian DNSPs, Consultation Paper submission, p. 4.

policies and practices of the DNSP, thereby increasing confidence of market participants and third parties in the accuracy of the content of the DAPR.

Having considered submissions to the consultation paper, the Commission is of the view that there are already a number of regulatory mechanisms and incentives to ensure that DNSPs deliver robust, high quality DAPRs in line with the rules. For example, the AER has the authority to investigate possible breaches of the rules, including where any information published in a DAPR is thought to be erroneous. In addition, any document published by a DNSP represents the view of the business and will subject to the internal process considered appropriate by each DNSP. On this basis, it is unlikely that a DNSP would include inaccurate or misleading information in its DAPR as it would carry a significant reputational risk for the company. For these reasons, the Commission has removed this requirement from the draft rule.

6.4 Rule making test

The Commission is satisfied that the distribution annual reporting arrangements as set out in the draft rule will, or are likely to, better contribute to the achievement of the NEO relative to the proposed rule. The draft rule is likely to promote efficient investment in distribution networks for the long term interests of consumers of electricity in the following ways:

- introducing transparent, nationally consistent planning arrangements which should help to ensure that DNSPs and other relevant parties make efficient planning and investment decisions when operating in the NEM;
- providing consistent and clearly defined reporting requirements for DNSPs in all participating jurisdictions will provide regulatory certainty and assist DNSPs in making efficient planning decisions, thereby promoting efficient investment in distribution networks;
- ensuring that network users understand how the timing and location of connections might affect capability of the network and the need for augmentations or non-network options, thereby promoting the efficient use of electricity services; and
- balancing the benefits of reporting information on DNSPs network planning activities with the costs of doing so, thereby promoting good regulatory practice.

7 Demand side engagement strategy

This chapter sets out the Commission's views in relation to the demand side engagement strategy, having regard to the views of stakeholders in submissions to the consultation paper. This chapter is structured as follows:

- section 7.1 describes the demand side engagement strategy as proposed by the proponent and summarises stakeholder responses to the consultation paper on this matter;
- section 7.2 sets out the Commission's proposed amendments to the proposed rule and a description of the draft rule on this matter;
- section 7.3 provides a summary of the Commission's analysis and assessment of the demand side engagement strategy draft rules; and
- based on the Commission's assessment in section 7.3, section 7.4 sets out the Commission's conclusions on this matter.

7.1 Proposed rule

7.1.1 Description of the proposed rule

The proposed rule contains a number of obligations on DNSPs in respect of their engagement with non-network providers during the annual planning process. This includes requiring that DNSPs:

- engage with non-network providers and consider non-network options at the planning stage; and
- develop a demand side engagement strategy.

The proposed demand side engagement strategy would require DNSPs to:

- prepare and publish a *demand side engagement document* that sets out its process and procedures for engaging with non-network providers and assessing non-network options as alternatives to network investment;
- establish, maintain and publish a *demand side engagement database* of non-network proposals and/or case studies that demonstrate assessments it has undertaken in considering non-network proposals; and
- establish and maintain a *demand side engagement register* for parties wishing to be advised of relevant developments related to a DNSP's planning activities.

DNSPs would need to publish the first demand side engagement document by the date nine months after the commencement of the rule. The proposed rule also requires

DNSPs to review and publish the demand side engagement strategy at least once every three years.

The demand side engagement strategy is intended to recognise the importance of proactive engagement between DNSPs and non-network providers in developing potential solutions to network constraints. This proposal was originally recommended in the AEMC's Distribution Network Planning and Expansion Review in response to stakeholder concerns that it can be difficult to engage with DNSPs at an appropriate stage in the planning process, and that there is limited transparency on how DNSPs assess and consider non-network options.

A number of DNSPs currently have in place comparable demand side obligations under jurisdictional instruments.[139] The proposed rule builds on current industry practice to impose similar obligations at a NEM-wide level.

7.1.2 Proponent's view

The proponent considers that the introduction of a demand side engagement strategy would facilitate ongoing relationships between DNSPs and non-network providers, while also encouraging DNSPs to consider all feasible options for network development. In addition, the proponent suggests that greater transparency and consultation around how DNSPs consider alternative investment options will encourage DNSPs to develop and operate their networks more efficiently. This may ultimately provide for lower network charges for end use customers.

7.1.3 Stakeholder views

Demand side engagement strategy

The consultation paper asked stakeholders for their views on the benefits and costs associated with implementing the demand side engagement strategy. Overall, EnerNOC and the Total Environment Centre (TEC) considered the benefits of DNSPs developing a demand side engagement strategy would outweigh the cost of the strategy.[140] In respect of costs, several DNSPs suggested these may include additional resources, information technology, publishing tools and businesses processes which would need to be established and maintained.[141]

More generally, Aurora Energy considered that its customer base would not be willing to pay the costs arising from implementing the strategy as they relate to a 'perceived' rather than an 'actual' failure.[142] The TEC suggested that the cost of developing the

139 Currently only New South Wales (NSW) and South Australia (SA) have comparable arrangements.

140 EnerNOC, Consultation Paper submission, p. 4; TEC, Consultation Paper submission, p. 4.

141 Energex, Consultation Paper submission, p. 2; Aurora Energy, Consultation Paper submission, p. 3; Endeavour Energy, Consultation Paper submission, p. 3; Victorian DNSPs, Consultation Paper submission, p. 14.

142 Aurora Energy, Consultation Paper submission, p. 3.

strategy could be passed through or recouped from Demand Side Participation (DSP) projects.[143]

The ENA and Ergon Energy considered that the rule should provide for DNSPs to be able to apply for an exemption or variation to the demand side engagement strategy where, due to operational or resource reasons, the costs of complying would manifestly exceed any benefit that may be reasonably obtained from compliance.[144]

In addition, the ENA and Ausgrid considered that the most effective way to improve the uptake of non-network options was through clear and appropriate incentives rather than prescriptive process requirements such as the strategy.[145] As evidence of this, Ausgrid noted that in NSW, the D-factor incentive regime was more successful than the NSW Demand Management Code.[146] In addition, EnerNOC considered that DNSPs would need to cooperate with non-network providers for the demand side engagement strategy to work in practice.[147]

Demand side engagement document

Energex was of the view that the demand side engagement document should not contain or replicate information which is or will be publicly available elsewhere, for example, through the connection process contained in Chapter 5A of the NER and associated publication requirements to be established under the NECF.[148] Energex considered that, for information available elsewhere, a specific reference to that source would be sufficient. In addition, Endeavour Energy did not see the need for a separate demand side engagement strategy given the requirements of the DAPR.[149]

Demand side engagement database

The majority of DNSPs who provided a submission to the consultation paper did not support the proposal to develop and maintain a database of non-network proposals and/or case studies.[150]

The ENA, Energex and the Victorian DNSPs considered the need to remove confidential information from the proposals would negate the value of the information within the database.[151] Similarly, Endeavour Energy considered the database would

143 TEC, Consultation Paper submission, p. 4.

144 ENA, Consultation Paper submission, p. 6; Ergon Energy, Consultation Paper submission, p. 6.

145 ENA, Consultation Paper submission, p. 6; Ausgrid, Consultation Paper submission, p. 3.

146 Ausgrid, Consultation Paper submission, p. 3.

147 EnerNOC, Consultation Paper submission, p. 3.

148 Ergon Energy, Consultation Paper submission, p. 12.

149 Endeavour Energy, Consultation Paper submission, pp. 2-3.

150 ENA, Consultation Paper submission, p. 7; Ergon Energy, Consultation Paper submission, pp. 5, 13; Energex, Consultation Paper submission, p. 2; Victorian DNSPs, Consultation Paper submission, pp. 3, 9, 14; Endeavour Energy, Consultation Paper submission, pp. 2-3; Essential Energy, Consultation Paper submission, p. 4.

151 ENA, Consultation Paper submission, p. 7; Energex, Consultation Paper submission, p. 2; Victorian DNSPs, Consultation Paper submission, pp. 3, 9, 14.

be difficult to implement due to the level of commercially sensitive information. Endeavour Energy suggested that either the rules or an AER guideline provide a template for this information to minimise commercial sensitivities.[152]

Further, Ergon Energy considered that even though DNSPs would have discretion to select data to be published, there would be a risk of inadvertently disclosing commercially sensitive information of non-network proposals. Ergon Energy also noted that additional resources would be required to administer the database, and this may lead to reporting duplication given that detail of proposals would be published in the RIT-D project specification report.[153]

The Victorian DNSPs noted that the existence of the database would not, in itself, increase demand side participation, and would not aid in contributing to the NEO.[154]

Demand side engagement register

The ENA and Ergon Energy did not support the proposal for DNSPs to establish and maintain an individual register of interested parties. The ENA considered this was an inefficient and costly approach to facilitating information between DNSPs and non-network proponents and suggested a central repository would be more appropriate.[155] In addition, Ergon Energy considered that the proposal would undermine the development of a national market and increase the burden on non-network providers by requiring them to register separately with each DNSP. Ergon Energy also expressed support for a central registration system for non-network providers managed by AEMO.[156]

7.2 Application of the proposed rule and proposed modifications

The draft rule has largely adopted the proposed rules in relation to the demand side engagement strategy, subject to several policy modifications and a number of amendments to improve and clarify the application of the rule. The manner and reasoning for these amendments are set out below.

7.2.1 Policy amendments

Having regard to the views of stakeholders, and having undertaken its own analysis and review, the Commission has, in the draft rule, made several modifications to the proposed rule to improve the application of the rule and better promote the NEO. This modification is as follows:

152 Endeavour Energy, Consultation Paper submission, pp. 2-3.

153 Ergon Energy, Consultation Paper submission, pp. 5, 13.

154 Ergon Energy, Consultation Paper submission, pp. 5, 13.

155 ENA, Consultation Paper submission, p. 7.

156 Ergon Energy, Consultation Paper submission, pp. 13-14.

- *Demand side engagement database*: the draft rule removes the obligation on DNSPs to establish, maintain and publish a database of non-network proposals and/or case studies as part of the demand side engagement strategy.[157] However, additional requirements have been added to the demand side engagement document requiring DNSPs to provide an example of a best practice non-network proposal, and a worked example of the assessment process, to support existing content.[158]

7.2.2 Amendments to improve clarity and application

The Commission has made a number of amendments to improve and clarify the application of the demand side engagement requirements in the proposed rule without affecting the principles underlying the proposed rule. These changes are as follows:

- *Purpose clause*: the draft rule removes the demand side engagement strategy purpose clause.[159]

- *Demand side engagement obligations*: the draft rule clarifies the obligation on DNSPs in respect of demand side engagement.

- *Content of the demand side engagement document*: detail regarding the content of the demand side engagement document has been moved from the body of the rule into a new schedule 5.9 for ease of reference.

- *Other minor changes*: to reflect comments made in submissions to the consultation paper, the draft rule includes a number of other minor drafting amendments. The policy issues log set out in Appendix A, and the legal issues log set out in Appendix B, provide further details of these amendments.

7.2.3 Description of the draft rule

Having regard to the amendments set out above, the key features of the demand side engagement strategy draft rules are described below.

Box 7.1: Demand side engagement obligations

Requirements:

- Each DNSP must develop a strategy for:
  - engaging with non-network providers; and

157 Proposed clause 5.6.2AA(o).

158 Draft schedule 5.9(d).

159 This clause did not impose binding requirements and demand side obligations on any party.

- considering non-network options.[160]

- A DNSP must engage with non-network providers and consider non-network options for addressing system limitations in accordance with its demand side engagement strategy.[161]

- A DNSP must document its strategy in a demand side engagement document which must be published no later than nine months after the date of commencement of the rule.[162]

- A DNSP must include the information specified in new schedule 5.9 in its demand side engagement document.[163]

- A DNSP must review and publish a revised demand side engagement document at least once every three years.[164]

- A DNSP must establish and maintain a facility by which parties can register their interest in being notified of developments relating to distribution network planning and expansion. This facility must be in place by the time the DNSP publishes its first demand side engagement document.[165]

Demand side engagement document:

- The following information must be included in a DNSP's demand side engagement document:[166]

  - a description of how the DNSP will investigate, develop, assess and report on potential non-network options;[167]

  - a description of the DNSP's process to engage and consult with potential non-network providers to determine their level of interest and ability to participate in the development process for potential non-network options;[168]

160 Draft clause 5.13.2(e).

161 Draft clause 5.13.2(f).

162 Draft clause 5.13.2(g).

163 Draft clause 5.13.2(h).

164 Draft clause 5.13.2(I).

165 Draft clause 5.13.2(j).

166 Draft schedule 5.9.

167 Draft schedule 5.9(a).

168 Draft schedule 5.9(b).

- an outline of the process followed by the DNSP when negotiating with non-network providers to further develop a potential non-network option;[169]
- an outline of the information a non-network provider is to include in a non-network proposal including, where possible, an example of a best practice non-network proposal;[170]
- an outline of the criteria that a potential non-network provider is to meet or consider in any offers or proposals;[171]
- an outline of the principles that the DNSP considers in developing the payment levels for non-network options;[172]
- a reference to any applicable incentive payment schemes for the implementation of non-network options and whether any specific criteria is applied by the DNSP in its application and assessment of the scheme;[173]
- the methodology to be used for determining avoided customer transmission use of system (TUOS) charges, in accordance with the relevant clauses;[174]
- a summary of the factors the DNSP takes into account when negotiating connection agreements with embedded generators;[175]
- the process used, and a summary of any specific regulatory requirements, for setting charges and the terms and conditions of connection agreements for embedded generating units;[176]
- the process for lodging a connection application for an embedded generating unit and the factors taken into account by the DNSP when assessing connection applications;[177]
- worked examples to support the description of how the DNSP will assess potential non-network options (in accordance with new schedule 5.9(a));[178]

169 Draft schedule 5.9(c).

170 Draft schedule 5.9(d).

171 Draft schedule 5.9(e).

172 Draft schedule 5.9(f).

173 Draft schedule 5.9(g).

174 Draft schedule 5.9(h).

175 Draft schedule 5.9(I).

176 Draft schedule 5.9(j).

177 Draft schedule 5.9(k).

- a link to any to any relevant, publicly available information produced by the DNSP;[179]
- a description of how parties may be listed on the demand side engagement register;[180] and
- the DNSP's contact details.[181]

7.3 Commission's assessment

The Commission has analysed and assessed the policy and drafting issues arising from the rule change request in respect of the proposed demand side engagement strategy. Outlined below is the Commission's assessment of this aspect of the draft rule, including the reasons why it considers this aspect of the draft rule better meets the NEO then the proposed rule.

7.3.1 Demand side engagement obligations

The proposed demand side engagement strategy was originally recommended in the AEMC's Distribution Network Planning and Expansion Review on the basis of stakeholder concerns that it can be difficult to engage with DNSPs at an appropriate stage in the planning process, and that there is limited transparency on how DNSPs assess and consider non-network options.[182]

The draft rule seeks to address these concerns by introducing several demand side engagement obligations on DNSPs, including a requirement to develop and document a demand side engagement strategy, and an obligation to engage with non-network providers and consider non-network options in accordance with this strategy. These obligations will encourage engagement of non-network providers in the planning and development process and provide the basis for the development of on-going working relationships between these parties.

In particular, the Commission supports the requirement for DNSPs to prepare and publish a document detailing their processes and procedures for assessing non-network options and interacting with non-network providers. Greater transparency and clarity around how DNSPs consider and assess alternatives to network investment should facilitate more efficient planning and investment decisions being made by both non-network providers and DNSPs.

178 Draft schedule 5.9(l).

179 Draft schedule 5.9(m).

180 Draft schedule 5.9(n).

181 Draft schedule 5.9(o).

182 AEMC 2009, *Review of National Framework for Electricity Distribution Network Planning and Expansion*, Final Report, 23 September 2009, Sydney, p. 15.

The demand side engagement strategy also requires DNSPs to establish and maintain a facility by which parties may register their interest in being notified of developments relating to distribution network planning. Contrary to the views of a number of stakeholders, the Commission considers that the requirement to establish a register of interested parties is an efficient and cost effective method of facilitating information flow between DNSPs and non-network proponents. The register should therefore also assist in promoting efficient investment in the distribution network over time.

Demand side engagement database

Under the proposed rule, as part of its demand side engagement strategy, DNSPs would be required to develop and maintain a database of proposals and/or case studies that demonstrate the project proposal and assessment process. The purpose of the database was to facilitate communication between parties and assist non-network providers to develop proposals for non-network options that could be processed by DNSPs more efficiently.

While the Commission supports the intent of this proposal, it is not satisfied that the requirement to establish a database is the most efficient means of achieving this objective. Consequently, the draft rule requires DNSPs to supplement several pieces of key information proposed for inclusion in the demand side engagement document, with examples.[183] The Commission considers that providing further transparency around DNSPs assessment processes in this manner should assist non-network providers in developing useful proposals for efficient assessment by DNSPs, without being overly onerous or costly for DNSPs.

7.4 Rule making test

The Commission is satisfied that the demand side engagement obligations as set out in the draft rule will, or are likely to, better contribute to the achievement of the NEO relative to the proposed rule. The draft rule is likely to promote efficient investment in distribution networks for the long term interests of consumers of electricity through:

- providing transparency regarding the consideration and assessment of non-network solutions by DNSPs, thereby helping to ensure efficiency in the provision of non-network solutions by non-network providers; and
- encouraging the engagement of non-network providers in network planning and development which will assist DNSPs in uncovering the full range of efficient investment options, thereby promoting efficient outcomes over time.

183 DNSPs would be required to review and update these examples (where appropriate), at least once every three years in line with the review of the demand side engagement document.

8 Joint planning arrangements

This chapter sets out the Commission's views in relation to the joint planning process as proposed by the proponent, having regard to the views of stakeholders in submissions to the consultation paper. This chapter is structured as follows:

- section 8.1 describes the joint planning arrangements as proposed by the proponent and summarises stakeholder responses to the consultation paper on this matter;
- section 8.2 sets out the Commission's proposed amendments to the proposed rule and a description of the draft rule on this matter;
- section 8.3 provides a summary of the Commission's analysis and assessment of the joint planning draft rules; and
- based on the Commission's assessment in section 8.3, section 8.4 sets out the Commission's conclusions on this matter.

8.1 Proposed rule

8.1.1 Description of the proposed rule

The proposed rule for joint planning contains a number of key elements.[184] These include requiring that:

- each DNSP conduct joint planning with any TNSP which operates a transmission network connected to the DNSP's network;
- the relevant DNSP and TNSP meet on a regular and as required basis to carry out joint planning of their networks over the relevant forward planning period; and
- the relevant DNSP and TNSP use reasonable endeavours to ensure efficient planning outcomes and to identify the most efficient investment options.

In carrying out their joint planning obligations, the DNSPs and TNSPs would be required to:

- identify any system limitations that: (1) will affect both the distribution and transmission networks of the relevant NSPs, or (2) will require coordination by both NSPs to address the system limitation;
- where the need for augmentation or a non-network option is identified, jointly determine plans that can be considered by relevant registered participants, AEMO, interested parties and parties on the demand side engagement register;

184 Joint planning refers to the planning processes and activities undertaken collectively by multiple NSPs to address any common problems which may impact their networks.

- carry out the requirements of the RIT-T for the identified need; and
- agree on a lead party to carry out the requirements of the RIT-T.

The proposed rule also clarifies that DNSPs must meet with each other regularly to undertake joint planning where there is a need to consider any augmentation or non-network option that affects more than one distribution network. It is noted that there are currently no specific provisions in the rules reflecting the joint planning work undertaken between DNSPs.

The proposed rule is largely consistent with the current requirements for joint planning under clause 5.6.2 of the NER. Aside from providing clarification on several aspects of the existing arrangements, the key change relates to the proposal for the RIT-T to be applied to all joint investments identified through the TNSP-DNSP joint planning process. This is intended to ensure that the most economically efficient investment option to address a relevant system limitation is identified and, potentially, adopted.

8.1.2 Rule change proponent's view

The proponent considered that the proposed joint planning arrangements (included within the annual planning requirements) would provide greater clarity around the processes for joint planning between DNSPs and TNSPs. This would, in turn, provide for greater efficiency in the development of distribution and transmission networks.

Further, as DNSPs and TNSPs would be required to use the RIT-T to assess any joint network investments and assess a broader range of market benefits, the proponent considered the proposed rule would ensure that the most economically efficient option to address a joint need for investment was identified and adopted.

8.1.3 Stakeholder views

Joint planning obligations of DNSPs and DNSPs

While stakeholders were generally supportive of the proposals to clarify the TNSP to DNSP joint planning arrangements, Aurora Energy did not consider that the proposed rule was sufficiently clear in respect of the arrangements for DNSP to DNSP joint planning.[185] Energex also requested clarification in relation to which DNSP would be required to undertake a RIT-D where there was a multitude of network owners involved in a single project.[186]

Project assessment process for joint planning projects

In submissions to the consultation paper, stakeholders expressed considerable concern in relation to the proposal for the RIT-T to be applied to all network investment projects identified through the joint planning process.

185 Aurora Energy, Consultation Paper submission, p. 7.

186 Energex, Consultation Paper submission, p. 6.

The ENA considered that, in the majority of cases, investment resulting from the joint planning process would not have a material market effect. The ENA considered that a material market effect would only ever likely occur where joint planning lead to reinforcement of the interconnected transmission network either to: (1) ensure a distribution network met the minimum power system security and reliability standards; or (2) replace distribution assets.[187]

The ENA and Ausgrid considered the RIT-T should only be performed where the preferred solution to address a distribution limitation was a transmission solution; where the preferred solution to address a distribution limitation was a distribution solution (even where a transmission solution may be an option), the RIT-D should be performed.[188]

In addition, Energex did not support the RIT-T being undertaken in all circumstances where expenditure on a transmission network was required. It considered a more practical alternative would be for the RIT-T to be undertaken only where there was a material increase in transmission capacity (the RIT-D would be undertaken where there is a material increase in the distribution network).[189]

Further, the ENA and ETSA Utilities queried whether a TNSP or DNSP would be required to perform the RIT-T where an investment was required to address a distribution limitation.[190] The ENA was of the view that TNSPs should always be the lead party where the RIT-T project assessment process was required. It considered this was appropriate on the basis that DNSPs would not be equipped, nor have sufficient resources, to undertake the RIT-T in addition to the RIT-D.[191] More generally, ETSA Utilities considered further clarity was required in the rule as to when each test (the RIT-T or RIT-D) would need to be performed and by which party (a TNSP or DNSP).[192]

Treatment of dual function assets

Ausgrid noted that the provisions regarding joint network investment require clarification on the AEMC's policy intent regarding the treatment of these investments. It noted that this issue was of particular concern to Ausgrid given it is both a TNSP and DNSP for the purpose of Chapter 5, owns and operates dual function assets and undertakes detailed joint planning both internally as TNSP and DNSP, and as a TNSP and DNSP with TransGrid.[193]

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187 ENA, Consultation Paper submission, p. 10.

188 ENA, Consultation Paper submission, p. 10; Ausgrid, Consultation Paper submission, p. 5.

189 Energex, Consultation Paper submission, p. 5.

190 ENA, Consultation Paper submission, pp. 4, 10, 9, 20; ETSA Utilities, Consultation Paper submission, p. 5.

191 ENA, Consultation Paper submission, pp. 4, 10, 9, 20.

192 ETSA Utilities, Consultation Paper submission, p. 6.

193 Ausgrid, Consultation Paper submission, p. 5.

8.2 Application of the proposed rule and proposed modifications

The draft rule has largely adopted the MCE's proposed rule in relation to the obligations on parties to carry out joint planning as described above. However, the Commission proposes to amend the arrangements in relation to the regulatory investment test to apply to joint planning projects. The draft rule also makes several amendments to improve and clarify the application of the rule. The manner and reasoning for these amendments are set out below.

8.2.1 Policy amendments

Having regard to the views of stakeholders, and having undertaken its own analysis and review, the Commission has, in the draft rule, made a modification to the proposed rule to improve the application of the rule and better promote the NEO. This modification is as follows:

- *Project assessment process for joint planning projects*: the draft rule differs from the proposed rule in respect of the circumstances in which NSPs would be required to apply the RIT-T to projects identified through the joint planning process. The draft rule requires that the RIT-T be undertaken for joint planning projects in circumstances where at least one potential credible option[194] contains a network or non-network option on a transmission network with an estimated capital cost greater than $5 million. In other cases, NSPs would have the option of undertaking the RIT-D process as an alternative to the RIT-T process (where the relevant criteria are met).

8.2.2 Amendments to improve clarity and application

The Commission has made a number of amendments to improve and clarify the application of the joint planning arrangements in the proposed rule without affecting the principles underlying the proposed rule. These changes are as follows:

- '*RIT-T project*' *and* '*RIT-D project*': the draft rule includes these new definitions to clarify that the RIT-D (or RIT-T) would be applied to a 'project' to address the identified need rather than to expenditure on assets and services to address that need.

- '*joint planning project*': consistent with the concept of a RIT-T project and RIT-D project, the draft rule omits references to 'joint network investment' and instead refers to 'joint planning project'.

194 'Potential credible option' is included as a new local definition in the draft rule. It refers to an investment option which a RIT-T proponent or a RIT-D proponent (as the case may be) reasonably considers has the potential to be a credible option based on its initial assessment of the identified need. See chapter 9 for further discussion on this term.

- '*RIT-T proponent*' *and* '*RIT-D proponent*': the draft rule includes several new definitions to clarify that, in light of the joint planning arrangements, the lead party of the RIT-T (or RIT-D) may be either a DNSP or a TNSP.

- *Treatment of dual function assets*: in the context of joint planning, the draft rule clarifies that a TNSP does not include an NSP that is a TNSP only because it owns, controls or operates dual function assets.

- *Joint planning obligations of DNSPs with other DNSPs*: the draft rule clarifies that, in the context of DNSP to DNSP joint planning, DNSPs may agree on a lead party for carrying out the requirements of the RIT-D.[195]

- *Other minor changes*: to reflect comments made in submissions to the consultation paper, the draft rule includes a number of other minor drafting amendments. The policy issues log set out in Appendix A, and the legal issues log set out in Appendix B, provide further details of these amendments.

8.2.3 Description of the draft rule

Having regard to the amendments set out above, the key features of the joint planning draft rules are described below.

Box 8.1: Joint planning draft rule

New definitions:

- *joint planning project* means a project initiated to address a need identified under the relevant joint planning provisions.[196]

- *RIT-T project* means:[197]

  - a project initiated to address an identified need identified by a TNSP; or

  - a joint planning project if:

    - at least one potential credible option to address the relevant identified need includes a network or non-network option on a transmission network (other than dual function assets) with an estimated capital cost greater than $5 million; or

195 In this circumstances, relevant DNSPs other than the lead party will be taken to have discharged their obligation to undertake the RIT-D in respect of that project. See draft clause 5.14.2(c).

196 Draft clause 5.10.2.

197 ibid.

- the NSPs affected by the joint planning project have agreed that the RIT-T should apply to the project.

- *RIT-D project* means:[198]
  - a project initiated to address an identified need identified by a DNSP; or
  - a joint planning project that is not a RIT-T project.
- *RIT-T proponent* means the NSP applying the RIT-T to a RIT-T project to address an identified need. The RIT-T proponent may be a DNSP or a TNSP if the identified need is identified through joint planning. In all other cases the RIT-T proponent would be a TNSP.[199]
- *RIT-D proponent* means the NSP applying the RIT-D to a RIT-D project to address an identified need. The RIT-D proponent may be a DNSP or a TNSP if the identified need is identified through joint planning. In all other cases a RIT-D proponent would be a DNSP.[200]

Joint planning obligations of TNSPs and DNSPs:

- Each DNSP must conduct joint planning with each TNSP of the transmission networks to which the DNSP's networks are connected.[201]
- Each TNSP must conduct joint planning with each DNSP of the distribution networks to which the TNSP's networks are connected.[202]
- For the purposes of this clause, a TNSP does not include an NSP that is a TNSP only because it owns, controls or operates dual function asset.[203]
- The relevant TNSP and DNSP must:
  - meet regularly and as required to assess the adequacy of existing transmission and distribution networks and transmission-distribution connection points over the next five years and to undertake joint planning of projects which relate to both networks;[204]

198 ibid.

199 ibid.

200 ibid.

201 Draft clause 5.14.1(a)(1).

202 Draft clause 5.14.1(a)(2).

203 Draft clause 5.14.1(c).

204 Draft clause 5.14.1(d)(1).

- use best endeavours to work together to ensure efficient planning outcomes and to identify the most efficient options to address the needs identified under the relevant joint planning provisions;[205]
- identify any limitations or constraints:[206]
  - that will affect both the TNSP's and DNSP's network; or
  - which can only be addressed by corrective action that will require coordination of the TNSP and DNSP; and
- where the need for a joint planning project is identified:[207]
  - jointly determine plans that can be considered by relevant registered participants, AEMO, interested parties and parties registered on the relevant DNSPs' demand side engagement register;
  - determine whether the joint planning project is a RIT-T project or a RIT-D project; and
  - may agree on a lead party to be responsible for carrying out the RIT-T or the RIT-D (as the case may be) in respect of the joint planning project.

- If an NSP, as the lead party for one or more NSPs, undertakes the RIT-T or the RIT-D (as the case may be) in respect of a joint planning process, the other NSPs will be taken to have discharged their obligation to undertake the relevant test in respect of that project.[208]

Joint planning obligations of DNSPs and DNSPs:

- DNSPs must meet regularly and as required to undertake joint planning with other DNSPs where there is a requirement to consider the need for any augmentation or non-network options that affect more than one DNSP's network.[209]
- DNSPs involved in joint planning may agree on a lead party to be responsible for carrying out the RIT-D in respect of the joint planning project.[210]

205 Draft clause 5.14.1(d)(2).

206 Draft clause 5.14.1(d)(3).

207 Draft clause 5.14.1(d)(4).

208 Draft clause 5.14.1(e).

209 Draft clause 5.14.2(a).

210 Draft clause 5.14.2(b).

- If a DNSP, as the lead party for one or more DNSPs, undertakes the RIT-D in respect of a joint planning process, the other DNSPs will be taken to have discharged their obligation to undertake the RIT-D in respect of that project.[211]

8.3 Commission's assessment

The Commission has analysed and assessed the policy and drafting issues arising from the rule change request in respect of the proposed joint planning arrangements. Outlined below is the Commission's assessment of this aspect of the draft rule, including the reasons why it considers this aspect of the draft rule better meets the NEO then the proposed rule.

8.3.1 Joint planning obligations of DNSPs and TNSPs

The joint planning requirements set out in the draft rule apply to each DNSP with the TNSP of the transmission networks to which the DNSPs' network is connected and vice versa.[212] The draft rule recognises that the current processes adopted by TNSPs and DNSPs in carrying out joint planning activities appear to be working effectively. The purpose of the draft rule is therefore to ensure that current practices are clearly reflected in the rules.

In addition, the draft rule seeks to balance the obligations currently imposed on TNSPs in respect of conducting joint planning with DNSPs, with corresponding obligations on DNSPs.[213]

The Commission considers that the draft rule will promote the efficient operation of networks by ensuring that DNSPs and TNSPs are subject to a clearly defined and efficient joint planning process, allowing them to jointly identify, and begin the process of addressing, potential problems which affect both networks in a timely manner.

8.3.2 Joint planning obligations of DNSPs with other DNSPs

The draft rule includes a general provision which clarifies that, where there is a requirement to consider the need for any augmentation or non-network options that

211 Draft clause 5.14.2(c).

212 Draft clause 5.14.1(a)(2) is intended to capture the mutual obligation on TNSPs to consult with each relevant DNSP for the purposes of the transmission annual planning review. See proposed clause 5.6.2(b1).

213 Currently, the rules require TNSPs to be the lead party in conducting joint planning with DNSPs. The draft rule seeks to balance this provision by placing an obligation on DNSPs to conduct joint planning with TNSPs and vice versa.

affect more than one DNSP's network, DNSPs will be required to meet regularly and as required to undertake joint planning with other DNSPs.[214]

In addition, the draft rule includes a new clause which clarifies that DNSPs would be expected to agree on a lead party for carrying out the requirements of the RIT-D where there are multiple DNSPs involved in a single project. This clarification has been provided in response to a request by Energex.

The DNSP to DNSP joint planning obligations set out in the draft rule are less prescriptive than the equivalent DNSPs to TNSPs joint planning obligations. The Commission notes that the degree of interaction required between DNSPs and the complexity of issues DNSPs face can vary significantly across jurisdictions. As such, it is appropriate to retain some flexibility within the rules rather than prescribe a detailed set of DNSP to DNSP joint planning procedures.

In addition, the Commission considers that the high level obligations provided in the draft rule are sufficient to make the arrangements transparent and clarify the instances where DNSPs are required to carry out joint planning. This view was broadly supported by DNSPs in their submissions to the consultation paper.[215]

8.3.3 Project assessment process for joint planning projects

Applicable regulatory investment test

The draft rule requires that the RIT-T project assessment and consultation process be applied to all joint planning projects where at least one potential credible option to address an identified need contains a network or non-network option on a transmission network (other than dual function assets) with an estimated capital cost greater than $5 million. In other cases, NSPs would have the option of undertaking the RIT-D process as an alternative to the RIT-T process (where the relevant RIT-D criteria are met).

The defining characteristic of a joint planning project is that both a transmission network and distribution network will be affected either by a limitation or constraint (the issue), or by the possible investment options to address a limitation or constraint (the possible solutions). Therefore, the location of a system limitation – that is, whether it is identified on a distribution network or transmission network – is less relevant in the context of joint planning than the impact that limitation has on the relevant networks.

On this basis, there is no clear rationale for maintaining existing arrangements which require the RIT-T to be applied to joint planning projects driven by the need to address a limitation on a transmission network, and the RIT-D (previously the regulatory test)

214 As noted, there are currently no specific provisions in the rules reflecting the joint planning work undertaken between DNSPs.

215 Aurora Energy was the only DNSP who considered that provisions similar to those provided in relation to TNSP-DNSP joint planning would be appropriate to further clarify the DNSP-DNSP joint planning arrangements. See Aurora Energy, Consultation Paper submission, p. 7.

to be applied to projects driven by the need to address an issue on a distribution network.[216] The Commission notes that such an approach may result in joint planning projects which are similar in terms of their impact on a relevant distribution and transmission network, being subject to project assessment processes which differ in detail and rigour, without clear reason.[217]

Instead, the Commission's view is that, generally, a single project assessment and consultation process should be applied to all joint planning projects, irrespective of the location of a system limitation. This approach would ensure that all joint planning projects are subject to an equally transparent project assessment process, an equally robust cost benefit assessment and an equally comprehensive consultation process.

In addition, the Commission considers that the RIT-T process, rather than the RIT-D, is the appropriate process to apply to joint planning projects, as the general rule. Given that joint planning projects will, by definition, affect both a transmission network and a distribution network,[218] the quantification of market benefits would be a key factor in a joint planning project's broader assessment to identify the most economic investment option. On the basis that the RIT-T mandates the quantification of material market benefits, application of the RIT-T to joint planning projects would ensure that any applicable market benefits were appropriately considered and quantified.[219]

With that said, the Commission notes a concern raised by DNSPs relation to the application of the RIT-T to projects involving minimal transmission investment, undertaken to address limitations on a distribution network.[220] The key concern (as understood by the Commission) is that, in these cases, outcomes of the joint planning process would be unlikely to have a material market impact, and hence would be unlikely to deliver material market benefits. Undertaking a project assessment and consultation process designed specifically to capture material market benefits may

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216 Under the RIT-T rules, TNSPs are required to conduct the RIT-T for investment project to address an issue on the transmission network (subject to the exemptions set out in clause 5.6.5C). Investment projects to address an issue on a distribution network are subject to the existing regulatory test (note that the rules provide for application of the regulatory test by TNSPs (under joint planning processes) for transmission investment that supports the distribution network).

217 This is due to differences in the level of detail and rigour of the RIT-T and RIT-D project assessment and consultation processes.

218 A joint planning project means a project initiated to address a need identified under draft clauses 5.14.1(d)(3) or 5.14.2. In respect of joint planning between a TNSP and DNSP, a joint planning project is a project initiated to address any limitations or constraints which affect both a TNSP's and DNSP's network or which can only be addressed by corrective action that will require coordination of the TNSP and DNSP.

219 The RIT-T and RIT-D project assessment and consultation processes, although similar, contain several differences designed to cater to the specific characteristics of transmission and distribution investments (respectively). For example, the RIT-T mandates the quantification of material market benefits on the basis that the values of market benefits which may be delivered by transmission investments tend to be larger and more widespread than those delivered in distribution. Under the RIT-D, this quantification is optional.

220 ENA, Consultation Paper submission, p. 4; Energex, Consultation Paper submission, p. 5.

therefore impose a regulatory burden on the relevant NSPs, with minimal potential benefit.[221]

To address this concern, the draft rule differs from proposed rule by providing NSPs with the option of applying the RIT-D (rather than the RIT-T) in instances where the opportunities for the delivery of material market benefits are limited. This circumstance has been proxied by use of the existing $5 million RIT-T cost threshold.[222] The draft rule therefore provides that where none of the potential credible options to address a system limitation contains a network or non-network option on a transmission network with an estimated capital cost greater than $5 million (or any other amount as varied by the RIT-T cost threshold review), NSPs would have the option of carrying out the requirements of the RIT-D as an alternative to the RIT-T (where the relevant RIT-D criteria are met).

By providing some flexibility in the approach to assessing joint planning projects, the Commission considers that the draft rule achieves an appropriate balance between the regulatory burden placed on NSPs in conducting the RIT-T, and the need to ensure that those joint planning projects likely to deliver material market benefits are subject to a robust and comprehensive project assessment process.

Lead party to apply the applicable regulatory investment test

The draft rule provides for parties undertaking joint planning to agree on a lead party responsible for carrying out the requirements of the RIT-T (or the RIT-D, where appropriate).[223]

In its submission to the consultation paper, the ENA did not consider that it was appropriate to require DNSPs to carry out the requirements of the RIT-T on the basis that DNSPs would not be equipped nor have sufficient resources to do so. The ENA considered that TNSPs should always be the lead party in the instances a RIT-T assessment was required.[224]

While the Commission acknowledges this concern, it does not agree with the suggestion that TNSPs should always be the lead party when carrying out the requirements of the RIT-T.

It is important to note that while the rules provide for the relevant TNSP and DNSP to agree on a party to lead the relevant regulatory investment test process, the selection of a lead party does not preclude the other parties' participation in the process. The draft

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221 These stakeholders suggested several alternate approaches to identifying the appropriate regulatory test to apply to joint planning projects. These suggestions, and the Commission's response, are set out in the issues log in Appendix A.

222 The Commission notes that transmission investments with a capital cost below the RIT-T cost threshold are less likely to have a material impact on a transmission network.

223 Where a lead party is agreed, the other parties would be deemed to have discharged their obligations to undertake the relevant regulatory investment test for the particular system limitation.

224 ENA, Consultation Paper submission, p. 10.

rule provides an outcome whereby parties are able to allocate the work required for the RIT-T project assessment process (or RIT-D process, where appropriate) among themselves, in light of the particulars of the matter in hand. It also requires the relevant NSPs to work together to meet the necessary regulatory requirements with the aim of identifying the most efficient investment options to address limitations and constraints identified on NSPs networks.[225]

Therefore, in instances where a DNSP is identified as the lead party for carrying out the requirements of the RIT-T, the Commission would expect the relevant TNSP to work closely with that DNSP in carrying out the requirements of the RIT-T, including providing input into any market benefits assessment.

8.3.4 Treatment of dual function assets

As noted in section 5.3.2, the draft rule retains the current approach to the treatment of dual function assets in relation to network annual planning, annual reporting and project assessment. However, there are a number of aspects of the joint planning arrangements set out in the proposed rule which would benefit from clarification in the draft rule in respect of the treatment of dual function assets. These areas are considered below.

Joint planning obligations of DNSPs and TNSPs

As noted above, the joint planning arrangements set out in draft clause 5.14.1 are intended to apply to each DNSP with the TNSP of the transmission networks to which the DNSP's network is connected and vice versa. On the basis that dual function assets predominately form part of a DNSP's distribution network,[226] these requirements are not intended to apply to DNSPs with TNSPs who are registered within the same organisation for the purposes of owning, controlling or operating dual function assets. In other words, these arrangements are not intended to prescribe the process for joint planning to be carried out internally by a DNSP in relation to the distribution assets and dual function assets which form its distribution network. This is intent is clarified in the draft rule.[227]

For the avoidance of doubt, a DNSP's 'distribution network' in this clause includes distribution assets and any dual function assets which the DNSP owns and operates. Therefore, in carrying out joint planning with a TNSP of a transmission network to which the DNSP's network is connected, a DNSP must plan (as relevant) having regard to its distribution assets and any dual function assets which may also form part of its distribution network.

225 As noted previously, the draft rule requires the relevant TNSPs and DNSPs to use best endeavours to work together to achieve efficient planning outcomes and investments.

226 See the definition of 'dual function asset' in NER Chapter 10.

227 Draft clause 5.14.1(c).

Applicable regulatory investment test

As noted in section 5.3.2, dual function assets will continue to be treated in the same manner as distribution assets for the purposes of the project assessment process. Therefore, consistent with the discussion in section 8.3.3 above, joint planning projects which include the possibility of expenditure on dual function assets will be subject to assessment under the RIT-T in all cases where at least one potential credible option to address an identified need contains a network or non-network option on a transmission network (other than dual function assets) with an estimated capital cost greater than $5 million.

8.3.5 Consequential changes to the RIT-T rules

The draft rules relating to joint planning require that a number of consequential changes be made to the rules in relation to the RIT-T (including to the RIT-T dispute resolution process).[228] These changes are not intended to alter the application of the RIT-T rules to projects other than joint planning projects. Rather, the changes are intended to facilitate integration of the joint planning provisions (including new definitions) into the existing rules and, in doing so, improve readability of the draft rule relative to the proposed rule. The key changes are as follows:

- references to '*transmission network service provider or distribution network service provider (as the case may be)*' have been removed and replaced with references to '*RIT-T proponent*';
- references to '*transmission investment or joint network investment (as the case may be)*' have been removed and replaced with references to '*RIT-T project*' or, where relevant, to '*network investment*';
- NER clauses 5.6.5C(a)(6) and (7) have been omitted on the basis that the application of the RIT-T to dual function assets has been clarified in the definition of joint planning projects;[229]
- NER clauses 5.6.5C(a)(4), (8) and (9) have been amended to ensure the provisions are capable of being applied in the joint planning context;[230] and
- other amendments to the format and location of clauses defining credible options and setting out the cost threshold determination process.

By ensuring the use of consistent language throughout the Chapter 5 Part B (where appropriate), the Commission considers that the non-material changes set out above will promote clarity of meaning and improve the overall readability of the rules.

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228 The relevant clauses are draft clause 5.15 and 5.16. The proposed rule also included a number of consequential changes to the RIT-T rules.

229 Draft clause 5.17.3(b).

230 Draft clauses 5.16.3(a)(4), (6)-(7).

8.4 Rule making test

The Commission is satisfied that the joint planning arrangements as set out in the draft rule will, or are likely to, better contribute to the achievement of the NEO relative to the proposed rule. The draft rule is likely to promote efficient investment in electricity networks for the long term interests of consumers of electricity through:

- providing greater clarity around the processes for joint planning between DNSPs and TNSPs, and DNSPs with other DNSPs, thereby promoting efficiency in the development of distribution and transmission networks; and

- improving consistency and transparency of joint planning project assessments, thereby promoting more efficient decision making by NSPs.

In addition, by providing some flexibility in the approach to assessing joint planning projects, the draft rule achieves an appropriate balance between the regulatory burden placed on NSPs in carrying out the project assessment and consultation process, and the need to ensure joint planning projects are subject to an appropriately robust and comprehensive project assessment process given the nature of the investment options.

9 Regulatory investment test for distribution

This chapter sets out the Commission's views in relation to the RIT-D, having regard to the views of stakeholders in submissions to the consultation paper. This chapter is structured as follows:

- section 9.1 describes the RIT-D as proposed by the proponent and summarises stakeholder responses to the consultation paper on this matter;
- section 9.2 sets out the Commission's proposed amendments to the proposed rule and a description of the draft rule on this matter;
- section 9.3 provides a summary of the Commission's analysis and assessment of the RIT-D draft rules; and
- based on the Commission's assessment in section 9.3, section 9.4 sets out the Commission's conclusions on this matter.

9.1 Proposed rule

9.1.1 Description of the proposed rule

The purpose of establishing the RIT-D process is to provide a framework for DNSPs to consider a range of potential options to address the investment needs of the network.[231] Under the proposed rule, the RIT-D process would be relevant where a need to investment in the distribution network has been identified 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.

Through the RIT-D process, a DNSP would be able to identify a technology-neutral credible option that maximises the net present value of economic benefits. In the case where the identified need is for reliability corrective action, it is possible that a preferred option may have a negative net economic benefit (that is, a net economic cost).

The RIT-D process would not apply to investments which relate to: urgent or unforeseen network issues; negotiated, alternative control and unclassified services; replacement and refurbishment expenditure; connection assets; or where the proposed investment has been identified through joint planning processes between DNSPs and TNSPs.

The proposed rule also specifies that the RIT-D must:

- be based on a cost-benefit analysis of reasonable scenarios for each credible option compared to the scenario where no option is implemented;

231 MCE, Rule Change Request, 30 March 2011, p. 4.

- include a level of analysis that is proportionate to the scale and potential impact of the credible options;
- be applied in a predictable, transparent and consistent manner; and
- include consideration of potential market benefits.

Under the proposed rule, the AER would be required to develop and publish the RIT-D and RIT-D application guidelines which are reflective of these principles. The RIT-D application guidelines would also be consistent with the RIT-D process proposed to be outlined in the NER. The RIT-D process would include the following stages:

- *An initial screening test* (the 'specification threshold test' or 'STT') to determine the appropriate RIT-D consultation and reporting requirements. Projects which meet the requirements of the STT would proceed to the project specification stage. All other projects would proceed directly to the project assessment stage.[232]
- *A project specification stage* where DNSPs would be required to consult on alternative proposals to meet the identified need before the project assessment stage. The recommended period for consultation would be four months.
- *A project assessment stage* involving 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 whether market benefits should be included. This information is to be set out by the DNSP in a final project assessment report.

In order to determine if non-network options have been duly considered, the proposed rule would also provide the AER with specific powers to:

- review a DNSP's policies and procedures to determine if non-network options have been duly considered; and
- audit projects which have been identified by DNSPs as not meeting the RIT-D threshold.

Under the proposed rule, the AER would also be required to publish a report by 31 March each year setting out the results of any audits undertaken over the previous 12 months.

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232 Under the proposed clause 5.6.6AB(c)-(e), DNSPs would be required to undertake a specification threshold test to assess: (1) the reasons for a proposed distribution investment, including the assumptions used in identifying the identified need; and (2) technically feasible non-network options that could either defer or remove the need for a proposed distribution investments to address the identified need. If, after undertaking the STT, a DNSP determined that there were no technically feasible non-network options to either defer or remove the need for a proposed distribution investment to address the identified need, the DNSP would not be required to publish a project specification report under proposed clause 5.6.6AB(g).

The proposed rule also included discrete proposals for the introduction of a dispute resolution process. These proposals are dealt with separately in chapter 10 of this determination.

Current arrangements

The current rules require DNSPs to carry out an economic cost effectiveness test for any distribution network investment project to identify potential investment options that satisfy the regulatory test.[233] The term 'cost effectiveness test' is used in the NER to refer to the reliability limb of the regulatory test whereby the lowest cost option of meeting a reliability obligation would be selected. Currently, the NER does not allow DNSPs to consider market benefits in their assessment of different investment options under this limb.[234]

For distribution projects with a capital cost above $10 million, the NER also requires DNSPs to consult on their economic cost effectiveness analysis and publish a report on the results of the cost effectiveness test.[235] Several jurisdictions also have in place additional requirements on DNSPs in respect of case-by-case project assessments and consultation, and project evaluations.[236]

It is intended that the new RIT-D process would replace the existing regulatory test requirements set out in the NER, and any supplementary jurisdictional arrangements.

9.1.2 Proponent's view

The rule change request states that the RIT-D process has been designed to ensure that DNSPs consider investment options in a transparent, consultative and technologically neutral manner. In doing so, the process is intended to facilitate the discovery and adoption of the most economically efficient investment option to address an identified need. The proponent considers that the process would increase efficiency in the development and operation of distribution networks, and potentially provide for more efficient network charges and improved reliability for consumers of electricity.[237]

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233 Since the commencement of the NEM, there has been a requirement to assess the economic contribution or feasibility of network augmentation investment proposals by means of a 'regulatory test', the form of which has varied over time. The regulatory test can be applied differently, depending on the primary purpose of the prospective investment. There are two possible limbs: (1) a reliability limb; and (2) a market benefits limb. For further information see www.aer.gov.au.

234 As such, the rules assume that all DNSP augmentations are driven by reliability obligations, which may not the case.

235 The rules do not require DNSPs to consult in relation to the economic assessment of projects nor explain their decisions in respect of investments under $10 million.

236 Both NSW and SA require a case-by-case project assessment of all proposed augmentations to evaluate the possibility of non-network solutions. In addition, only these two states specify an evaluation process that distributors should follow in considering projects. See AEMC 2009, *Review of National Framework for Electricity Distribution Network Planning and Expansion*, Scoping and Issues Paper, 12 March 2009, Sydney, p. 20.

237 MCE, Rule Change Request, 30 March 2011.

In addition, the proponent considers that clearer and more comprehensive information regarding DNSPs' decision making processes would assist other market participants such as TNSPs, connection applicants and non-network providers to make more efficient investment decisions when operating in the NEM. Detailed information regarding the economic justification of distribution investments may also assist the AER in its determination of DNSPs' revenues under Chapter 6 of the NER which should result in more efficient network charges.[238]

9.1.3 Stakeholder views

In submissions to the consultation paper, stakeholders raised a significant number of issues in relation to the proposed RIT-D. Several key themes emerged, specifically in relation to: the scope of the RIT-D (particularly the approach to applying the RIT-D cost threshold and the types of investments subject to the RIT-D); the operation of the specification threshold test; and the provision of specific review and audit powers for the AER. A summary of the key issues is set out below.

RIT-D cost threshold

A number of stakeholders expressed concern in relation to the application of the RIT-D cost threshold to the most expensive option which is technically and economically feasible.[239] Specifically, the ENA, Ergon Energy and Energex considered this approach would create a regulatory burden on DNSPs on the basis that:

- the term 'economically and technically' feasible could be broadly interpreted, thus increasing the likelihood of the most expensive option for investment being above $5 million; and
- such terminology world essentially require that DNSPs undertake a preliminary 'mini least cost regulatory investment test' prior to undertaking the specification threshold test.[240]

Stakeholders proposed a number of alternative approaches to applying the RIT-D cost threshold. For example, the ENA and Energex suggested the focus of the requirement be on the 'least expensive option'.[241] This was supported by Ergon Energy who considered that either the 'least expensive option' or, alternatively, the 'preferred option', should be the focus.[242] ETSA Utilities and the Victorian DNSPs considered the threshold should be set with reference to the capital cost of the 'preferred network

238 ibid.

239 ENA, Consultation Paper submission, pp. 4, 13, 15; Ergon Energy, Consultation Paper submission, pp. 4-5; Energex, Consultation Paper submission, pp. 9, 15; Victorian DNSPs, Consultation Paper submission, pp. 5, 16; ETSA Utilities, Consultation Paper submission, pp. 6-8.

240 ENA, Consultation Paper submission, pp. 4, 13, 5; Ergon Energy, Consultation Paper submission, pp. 4-5; Energex, Consultation Paper submission, pp. 9, 15.

241 ENA, Consultation Paper submission, pp. 4, 13, 15; Energex, Consultation Paper submission, pp. 9, 15.

242 Ergon Energy, Consultation Paper submission, pp. 4-5.

investment option'.[243] In addition, Essential Energy considered the provision would more meaningfully relate to the 'credible option' definition and use.[244]

In relation to the RIT-D cost threshold level, the AER expressed support for the $5 million figure on the basis that it provided consistency with the RIT-T and was sufficiently high that it would not create a significant RIT-D assessment burden on DNSPs.[245]

In contrast, the ENA, Endeavour Energy and the Victorian DNSPs questioned whether the $5 million cost threshold level was appropriate.[246] Endeavour Energy considered $5 million was too low and requested further consultation on the matter. The Victorian DNSPs considered the threshold should be no lower than $5 million.

Overall, Ergon Energy considered the RIT-D design parameters were an improvement on current arrangements and consistent with the NEO.[247]

Projects subject to the RIT-D

A number of stakeholders suggested several other classes of distribution investments should be excluded from assessment under the RIT-D.[248] In addition, a number of stakeholders requested clarity on whether the RIT-D would be required in certain circumstances.[249]

In relation to the exclusion of investments required to address urgent and unforeseen network issues, several stakeholders considered the timeframe of six months in the definition of 'urgent or unforeseen network issue'[250] was unrealistic given the lead times required for procurement of equipment, design and construction.[251] As a more reasonable alternative, these stakeholders suggested amending the timeframe to between 12 and 24 months.[252] Ergon Energy also suggested amending the terminology

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243 Victorian DNSPs, Consultation Paper submission, pp. 5, 16; ETSA Utilities, Consultation Paper submission, pp. 6-8.

244 Essential Energy, Consultation Paper submission, p. 7.

245 AER, Consultation Paper submission, p. 6.

246 ENA, Consultation Paper submission, p. 15; Endeavour Energy, Consultation Paper submission, pp. 6-8; Victorian DNSPs, Consultation Paper submission, pp. 5, 16.

247 Ergon Energy, Consultation Paper submission, p. 9.

248 ENA, Consultation Paper submission, p. 16; Ergon Energy, Consultation Paper submission, pp. 5, 17; ETSA Utilities, Consultation Paper submission, pp. 6-8.

249 Energex, Consultation Paper submission, pp. 7, 10, 18; Ergon Energy, Consultation Paper submission, p. 15; ETSA Utilities, Consultation Paper submission, pp. 6-8; ENA, Consultation Paper submission, p. 15; Ausgrid, Consultation Paper submission, pp. 6-8.

250 Proposed clause 5.6.5CB(c).

251 ENA, Consultation Paper submission, p. 16; Ergon Energy, Consultation Paper submission, p. 18; Victorian DNSPs, Consultation Paper submission, p. 5; Essential Energy, Consultation Paper submission, p. 7; ETSA Utilities, Consultation Paper submission, pp. 6-8.

252 Ergon Energy, Consultation Paper submission, p. 18; Victorian DNSPs, Consultation Paper submission, p. 5; Essential Energy, Consultation Paper submission, p. 7; ETSA Utilities, Consultation Paper submission, pp. 6-8.

from 'required to be operational' to 'required to be commenced'.[253] The ENA considered that rather than prescribe a more appropriate timeframe, urgent and unforeseen work should fall within the exemptions framework.[254]

In contrast to these views, the AER noted that it would be rare for a distribution project greater than $5 million to be urgent or unforeseen. On this basis, the AER was supportive of the proposed limitations on exemptions from the RIT-D for urgent and unforeseen projects. It considered these provisions would ensure that DNSPs could not exclude projects from assessment under the RIT-D process due to errors or deficiencies in a DNSPs own planning arrangements. The AER also considered that these provisions would restrict any "gaming opportunities" for a DNSP to delay project planning to avoid the RIT-D assessment process.[255]

Specification threshold test

While the majority of stakeholders appeared to support the purpose of the STT, several stakeholders considered that the proposed drafting required clarification as to which projects were intended to be streamlined through the RIT-D process.[256]

Specifically, several stakeholders considered the phrase 'technically feasible' was problematic and would result in DNSPs never being able to identify those projects originally intended to be streamlined through the RIT-D process, thereby rendering the STT ineffective.[257] As an alternative, the ENA and Energex suggested that 'technically feasible non-network options' be amended to 'credible non-network options' on the basis that this change would necessitate non-network options being both commercially and technically feasible, and able to be completed in a timely manner.[258] Ergon Energy considered this provision should be drafted to limit the number of assessments to only those proposals which could potentially be implemented.[259]

In addition, Ausgrid requested the inclusion of a more refined criteria than 'technically feasible' in order to determine when consultation on non-network options was considered appropriate. Ausgrid suggested guidance could be taken from the NSW Demand Management Code of Practice for Electrical Distribution.[260]

AER review and audit activities

The majority of DNSPs did not support the proposal to provide the AER with specific review and audit powers in relation to DNSPs consideration of non-network options,

253 Ergon Energy, Consultation Paper submission, p. 18.

254 ENA, Consultation Paper submission, p. 16.

255 AER, Consultation Paper submission, p. 8.

256 ENA, Consultation Paper submission, p. 4; Energex, Consultation Paper submission, p. 2.

257 ENA, Consultation Paper submission, p. 18; Energex, Consultation Paper submission, p. 13; ETSA Utilities, Consultation Paper submission, pp. 6-8.

258 ENA, Consultation Paper submission, p. 18; Energex, Consultation Paper submission, p. 13.

259 Ergon Energy, Consultation Paper submission, p. 21.

260 Ausgrid, Consultation Paper submission, p. 3.

noting that these activities would be captured by AER's existing functions and powers set out in legislation in relation to monitoring, investigating and enforcing compliance.[261] Specifically, Energex was opposed to this requirement on the basis that the framework in which DNSPs identify and determine these projects is already examined by the AER as part of the regulatory determination process.[262] Endeavour Energy considered the AER's existing powers of review through the dispute resolution process were appropriate and sufficient.[263]

Ergon Energy considered the prima facie position should be that a DNSP's policies and procedures are fully compliant with the rules and the prerequisite should be that the AER has valid reason for reviewing a DNSP's policies and procedures.[264]

In contrast, the AER, TEC and EnerNOC supported these proposals.[265]

In respect of the proposal requiring the AER to publish an annual audit report, a number of stakeholders considered that there was not sufficient justification for a separate report to be published. These stakeholders considered the results of any audits could be included in the quarterly compliance reports currently published by the AER.[266] The AER also questioned why this obligation was necessary given that it is the enforcement body for the NEM and publishes quarterly compliance reports and investigative reports on its enforcement and compliance activity.[267] The AER suggested that the proposal be drafted as an option rather than an obligation.

In contrast, Aurora Energy and EnerNOC were supportive of the requirement that the AER must publish an annual report detailing the results of any audit undertaken in the last 12 months.[268]

Re-application of the RIT-D

Energex suggested that the AEMC clarify the circumstances in which a DNSP would be expected to reapply the RIT-D.[269] In its supplementary submission, Energex noted that the issue of the re-application of the RIT-D was primarily driven by uncertainty

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261 Ergon Energy, Consultation Paper submission, p. 19; Energex, Consultation Paper submission, p. 18; Victorian DNSPs, Consultation Paper submission, p. 16; Ausgrid, Consultation Paper submission, pp. 6-8; Endeavour Energy, Consultation Paper submission, p. 9; Essential Energy, Consultation Paper submission, p. 7; Aurora Energy, Consultation Paper submission, p. 8.

262 Energex, Consultation Paper submission, p. 18.

263 Endeavour Energy, Consultation Paper submission, p. 9.

264 Ergon Energy, Consultation Paper submission, p. 19.

265 AER, Consultation Paper submission, p. 8; TEC, Consultation Paper submission, p. 5; EnerNOC, Consultation Paper submission, p. 6.

266 Ergon Energy, Consultation Paper submission, pp. 9-10; Energex, Consultation Paper submission, p. 19; Victorian DNSPs, Consultation Paper submission, p. 16; Endeavour Energy, Consultation Paper submission, p. 9; Essential Energy, Consultation Paper submission, p. 7.

267 AER, Consultation Paper submission, p. 8.

268 Aurora Energy, Consultation Paper submission, p. 8; EnerNOC, Consultation Paper submission, p. 6.

269 Energex, Consultation Paper supplementary submission, p. 3.

around the relationship between conducting a RIT-D and then building an option to address the identified limitation.[270] Energex considered that DNSPs should not be required to undertake multiple RIT-D assessments in relation to the same network limitations in instances where circumstances may change between a RIT-D assessment and commencement of construction.

In addition, the AER suggested that further thought should be given to whether DNSPs should be required to reapply the RIT-D in certain circumstances, including where a significant period of time has elapsed since completion of an original assessment.[271]

General comments

The ENA expressed concern that the overall complexity of the proposed RIT-D process would introduce unacceptable delays in the provision of electricity network infrastructure which may become the subject of compliance and enforcement disputes.[272]

The AER also expressed concern in respect of the proposed approach to setting out the principles underpinning the RIT-D. The AER noted that its preference would be for the rules to set out high level principles regarding the coverage of the RIT-D, with further details on the nature of the test and classes of costs and benefits to be set out in the RIT-D application guidelines.[273]

More generally, Aurora Energy noted that it did not support the introduction of the RIT-D on the basis that it appeared to be addressing a "perceived" rather than an "actual" failure. Aurora Energy considered that the RIT-D would be more administratively onerous than the current regulatory test, and that the changes proposed to allow for preferred non-network solutions could lead to issues in respect of reliability and security of supply.[274]

9.2 Application of the proposed rule and proposed modifications

The draft rule has largely adopted the proposed rules in relation to the RIT-D process described in section 9.1.1, subject to several policy modifications and a number of amendments to improve and clarify the application of the rule. The manner and reasoning for these amendments are set out below.

270 Energex, Consultation Paper, supplementary submission, p. 3.

271 AER, Consultation Paper submission, pp. 6-7.

272 ENA, Consultation Paper submission, p. 4.

273 AER, Consultation Paper submission, pp. 4-6.

274 Aurora Energy, Consultation Paper submission, p. 7.

9.2.1 Policy amendments

Having regard to the views of stakeholders, and having undertaken its own analysis and review, the Commission has, in the draft rule, made several modifications to the proposed rule to improve the application of the rule and better promote the NEO. These modifications are as follows:

- *Specification threshold test*: the draft rule takes a different approach to the concept of the STT (under the heading 'non-network screening process'). The draft rule does not require a RIT-D proponent[275] to prepare and publish a 'non-network options report' (previously the 'project specification report') where it has determined that there will not be a non-network option that is a potential credible option to address an identified need.

- *Project specification report*: the draft rule makes several changes to the project specification report (renamed the 'non-network options report') to ensure it is focussed on: (1) providing relevant information to non-network providers to assist them in considering, developing and proposing viable non-network options; and (2) seeking information from interested stakeholders on non-network options that are potential credible options, including on the range of materially relevant market benefits and costs.

- *Re-application of the RIT-D in certain circumstances*: the draft rule includes a new provision which clarifies that, unless otherwise determined by the AER, a RIT-D proponent must reapply the RIT-D where there is a material change in circumstances which, in the reasonable opinion of the RIT-D proponent, means that the preferred option identified in the original RIT-D assessment is no longer the preferred option.

- *AER review and audit activities*: the draft rule does not include additional powers for the AER to review and audit a DNSPs activities regarding the consideration of non-network options.

- *Additional classes of market benefits*: the draft rule does not permit a DNSP to consider any other class of market benefit it considers to be relevant when carrying out a RIT-D project assessment. However, the draft rule includes a new obligation on a RIT-D proponent to consider any other class of market benefit (or financial cost) determined to be relevant by the AER.

9.2.2 Amendments to improve clarity and application

The Commission has made a number of amendments to improve and clarify the application of the RIT-D arrangements in the proposed rule without affecting the principles underlying the proposed rule. The most notable changes are as follows:

275 'RIT-D proponent' is included as a new definition in the draft rule. It clarifies that, in light of the joint planning arrangements, a DNSP or a TNSP may carry out the requirements of the RIT-D where the relevant criteria are met. See chapter 8 for further discussion of this definition.

- *RIT-D cost threshold*: the terminology in the draft rule used to describe the approach to applying the RIT-D cost threshold level differs to that in the proposed rule such that a project would be exempt from the RIT-D where the estimated capital cost to the NSPs affected by the RIT-D project[276] of the most expensive potential credible option is less than $5 million (as varied in accordance with a cost threshold determination).

- *Potential credible option*: the draft rule includes a new definition to refer to an investment option which a RIT-T proponent or a RIT-D proponent (as the case may be) reasonably considers has the potential to be a credible option based on its initial assessment of the identified need.

- *Project specification report*: to better reflect the purpose and content of this report, the draft rule refers to the 'non-network options report' rather than to the 'project specification report'.

- *Form of RIT-D cost-benefit analysis*: the draft rule provides the AER with discretion to specify in the RIT-D (and RIT-D application guidelines) the appropriate form of cost-benefit analysis to apply in relation to projects driven by reliability issues and projects driven by the achievement of market benefits.

- *Content of final project assessment report*: the draft rule clarifies that where a RIT-D proponent is exempt from publishing a draft project assessment report, the content of its final project assessment report must include the matters that would otherwise have been included in a draft project assessment report.

- *Consultation with interested parties*: on the basis that there will be no definitive list of interested parties held by a DNSP, references to an NSP "seeking submissions from" interested parties have been replaced with a requirements for NSPs to "publish a request for submissions from" interested parties (and other stakeholders, where relevant).

- *Other minor changes*: to reflect comments made in submissions to the consultation paper, the draft rule includes a significant number of other minor drafting amendments. The policy issues log set out in Appendix A, and the legal issues log set out in Appendix B, provide further details of these amendments.

9.2.3 Description of the draft rule

Having regard to the amendments set out above, the key features of the RIT-D draft rules are described below. Figure 9.1 then sets out a summary of the RIT-D process.

276 'RIT-D project' is included as a new definition in the draft rule. It refers to either a project initiated to address an identified need identified by a DNSP or a joint planning project that is not a RIT-T project. See chapter 8 for further discussion of this definition.

Box 9.1: Regulatory investment test for distribution

RIT-D principles:

- The AER must develop and publish the RIT-D in accordance with the distribution consultation procedures.[277]
- The purpose of the RIT-D is to identify the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the market (the preferred option). For the avoidance of doubt, the preferred option may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the identified need is for reliability corrective action.[278]
- The RIT-D must:
  - be based on a cost-benefit analysis of each credible option;[279]
  - not require a level of analysis that is disproportionate to the scale and likely impact of each credible option being considered;[280]
  - be capable of being applied in a predictable, transparent and consist manner;[281]
  - require the RIT-D proponent to consider whether the credible option could deliver the following classes of market benefits:[282]
    - 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 costs for parties other than the RIT-D proponent due to:
      - differences in timing of new plant;
      - differences in capital costs; and
      - differences in the operating and maintenance costs;

277 Draft clause 5.17.1(a).

278 Draft clause 5.17.1(b).

279 Draft clause 5.17.1(c)(1).

280 Draft clause 5.17.1(c)(2).

281 Draft clause 5.17.1(c)(3).

282 Draft clause 5.17.1(c)(4).

- differences in the timing of expenditure;
- changes in load transfer capacity and the capacity of embedded generators to take up load;
- any additional option value gained or forgone from implementing the credible option with respect to the likely future investment needs of the market;
- changes in electrical energy losses; and
- any other market benefit determined to be relevant by the AER.

— with respect to the classes of market benefits relating to load shedding and customer interruptions, ensure that if the credible option is for reliability corrective action, the consideration and any quantification assessment will apply insofar as the market benefit delivered by the credible option exceeds the minimum standard required for reliability corrective action;[283]

— require the RIT-D proponent to consider whether the following classes of costs would be associated with the credible option and, if so, quantify the:[284]

- financial costs incurred in constructing or providing the credible option;
- operating and maintenance costs over the operating life of the credible option;
- cost of complying with laws, regulations and applicable administrative requirements in relation to the construction and operation of the credible option; and
- any other financial costs determined to be relevant by the AER;

— require a RIT-D proponent, in exercising judgement as to whether a particular class of market benefit or cost applies to a credible option, to have regard to any submissions received on the non-network option report and/or draft project assessment report (where relevant);[285]

283 Draft clause 5.17.1(c)(5).

284 Draft clause 5.17.1(c)(6).

285 Draft clause 5.17.1(c)(7).

- provide that any market benefit or cost which cannot be measured as a market benefit or cost to persons in their capacity as generators, DNSPs, TNSPs or consumers of electricity must not be included in any analysis under the RIT-D;[286] and

- specify:[287]

  - the method(s) permitted for estimating the magnitude of different classes or market benefits;

  - the method(s) permitted for estimating the magnitude of the different classes of costs;

  - the appropriate method and value for specific inputs for determining the discount rates or rates to be applied (where relevant);

  - that a sensitivity analysis is required for modelling the cost-benefit analysis; and

  - that the preferred option may, in some circumstances, have a negative net economic benefit where the identified need is for reliability corrective action or where the RIT-D proponent does not quantify market benefits during the project assessment process.

- A RIT-D proponent may, under the RIT-D, quantify each class of market benefits where the RIT-D proponent considers that:[288]

  - any applicable market benefits may be material; or

  - the quantification of market benefits may alter the selection of the preferred option.

- The RIT-D permits a single assessment of an integrated set of related but similar investments.[289]

Projects subject to the RIT-D:

- A RIT-D proponent must apply the RIT-D to a RIT-D project except in circumstances where:

286 Draft clause 5.17.1(c)(8).

287 Draft clause 5.17.1(c)(9).

288 Draft clause 5.17.1(d).

289 Draft clause 5.17.1(e).

- the RIT-D project is required to address an urgent and unforeseen network issue;[290]
- the estimated capital cost to the NSPs affected by the RIT-D project of the most expensive potential credible option to address the identified need is less than $5 million (as varied in accordance with a cost threshold determination);[291]
- the cost of addressing the identified need is to be fully recovered through charges other than charges in respect of standard control services or prescribed transmission services;[292]
- the identified need can only be addressed by expenditure on a connection asset;[293]
- the RIT-D project is related to the refurbishment or replacement of existing assets and is not intended to augment the network;[294] or
- the refurbishment and replacement expenditure also results in an augmentation to a network and the estimated capital cost of the most expensive potential credible option to address the identified need in respect of the augmentation component is less than $5 million (as varied in accordance with a cost threshold determination).[295]

- If a potential credible option to address an identified need includes expenditure on a dual function asset, the project must be assessed under the RIT-D (unless the need is subject to the RIT-T under joint planning).[296]
- A RIT-D project will be required to address an urgent and unforeseen network issue that would otherwise put at risk the reliability of the distribution network (or a significant part of that network) if:[297]
  - it is necessary that the assets or services to address the issue be operational within six months of the issue being identified;
  - the event or circumstance causing the identified need was not reasonably foreseeable by, and was beyond the reasonable control of, the NSPs that identified the need; and

290 Draft clause 5.17.3(a)(1).
291 Draft clause 5.17.3(a)(2).
292 Draft clause 5.17.3(a)(3).
293 Draft clause 5.17.3(a)(4).
294 Draft clause 5.17.3(a)(5).
295 Draft clause 5.17.3(a)(6).
296 Draft clause 5.17.3(b).
297 Draft clause 5.17.3(c).

- a failure to address the identified need is likely to materially adversely affect the reliability and secure operating state of the distribution network (or a significant part of that network).

- For each RIT-D project to which the RIT-D does not apply (with the exception of negotiated distribution and transmission services), the NSPs affected by the RIT-D project must ensure, acting reasonably, that the investment required to address the identified need is planned and developed at least cost over the life of the investment.[298]

- A RIT-D proponent must not treat different parts of an integrated solution to an identified need as distinct and separate options for the purposes of determining whether the RIT-D applies to each of those parts.[299]

RIT-D procedures:

Screening for non-network options:

- A RIT-D proponent must prepare and publish a non-network options report for all RIT-D projects except where a RIT-D proponent determines that there will not be a non-network option that is a potential credible option to address the identified need.[300]

- If a DNSP determines that a non-network options report is not required, then as soon as possible after making the determination it must publish on its website a notice setting out the reasons for its determination, including any methodologies and assumptions it used in making its determination.[301]

Non-network options report:

- A non-network options report must include:

  - a description of the identified need;[302]

  - the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-D proponent considers reliability corrective action is necessary);[303]

  - if available, the relevant annual deferred augmentation charge associated with the identified need;[304]

298 Draft clause 5.17.3(d).

299 Draft clause 5.17.3(e).

300 Draft clauses 5.17.4(b) and (c).

301 Draft clause 5.17.4(d).

302 Draft clause 5.17.4(e)(1).

303 Draft clause 5.17.4(e)(2).

- the technical characteristics of the identified need that a non-network option would be required to deliver, such as:[305]
  - the size and location of load reduction or additional supply;
  - location;
  - contribution to power system security or reliability;
  - contribution to power system fault levels;
  - the operating profile;
- a summary of potential credible options to address the identified need, as identified by the RIT-D proponent, including network and non-network options;[306]
- for each potential credible option, the RIT-D proponent must provide information, to the extent practicable, on:[307]
  - a technical definition or characteristics of the option;
  - the estimated construction timetable and commissioning date (where relevant); and
  - the total indicative capital cost (including capital and operating costs); and
- information to assist non-network providers wishing to present alternative potential credible options, including details of how to submit a non-network proposal for consideration by a RIT-D proponent.[308]

- The non-network options report must be published in a timely manner having regard to the ability of parties to identify the scope for, and develop, alternative potential credible options or variants to the potential credible options.[309]

304 Draft clause 5.17.4(e)(3).

305 Draft clause 5.17.4(e)(4).

306 Draft clause 5.17.4(e)(5).

307 Draft clause 5.17.4(e)(6).

308 Draft clause 5.17.4(e)(7).

309 Draft clause 5.17.4(f).

- At the time of publishing the report, the RIT-D proponent (if it is a DNSP) must notify parties on the DNSPs demand side engagement register of the report's publication.[310]
- Registered participants, AEMO, interested parties, non-network providers and (if relevant) persons registered on a DNSPs demand side engagement register must be provided with not less than four months in which to make submissions on the non-network options report from the date that the RIT-D proponent publishes the report.[311]

Draft project assessment report:

- If one or more Network Service Providers wishes to proceed with a RIT-D project following a determination under paragraph (c) or the publication of a non-network options report, then the RIT-D proponent, having regard, where relevant, to any submissions received on the non-network options report, must prepare and publish a draft project assessment report within:[312]
  - 12 months of:
    - the end of the consultation period on a non-network options report; or
    - where a non-network option report is not required, the publication of a notice to that effect; or
  - any longer time period as agreed in writing by the AER.
- The draft project assessment report must include the following information:
  - a description of the identified need;[313]
  - the assumptions used in identifying the identified need (including in the case of reliability corrective action, reasons that the RIT-D proponent considers reliability corrective action is necessary);[314]
  - if applicable, a summary of, and commentary on, the submissions to the non-network options report;[315]

310 Draft clause 5.17.4(g).

311 Draft clause 5.17.4(h).

312 Draft clause 5.17.4(I).

313 Draft clause 5.17.4(j)(1).

314 Draft clause 5.17.4(j)(2).

315 Draft clause 5.17.4(j)(3).

- a description of each credible option assessed;[316]
- where relevant, a quantification of each applicable market benefit for each credible option;[317]
- a quantification of each applicable cost for each credible option (including a breakdown of operating and capital expenditure);[318]
- a detailed description of the methodologies used in quantifying each class of cost and market benefit;[319]
- where relevant, the reasons why the DNSP has determined that a class of market benefit or cost does not apply to a credible option;[320]
- the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;[321]
- the identification of the proposed preferred option;[322]
- for the proposed preferred option, the DNSP must provide:[323]
  - details of the technical characteristics;
  - the estimated construction timetable and commissioning date (where relevant);
  - the indicative capital and operating cost (where relevant);
  - a statement and accompanying detailed analysis that the preferred option satisfies the RIT-D; and
  - if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent.
- contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed.[324]

316 Draft clause 5.17.4(j)(4).

317 Draft clause 5.17.4(j)(5).

318 Draft clause 5.17.4(j)(6).

319 Draft clause 5.17.4(j)(7).

320 Draft clause 5.17.4(j)(8).

321 Draft clause 5.17.4(j)(9).

322 Draft clause 5.17.4(j)(10).

323 Draft clause 5.17.4(j)(11).

324 Draft clause 5.17.4(j)(12).

- The RIT-D proponent must publish a request for submissions on the matters set out in the draft project assessment report, including the proposed preferred option, from registered participants, AEMO, non-network providers, interested parties and if the RIT-D proponent is a DNSP, persons on the DNSPs demand side engagement register.[325]
- The RIT-D proponent must consult directly with affected customers in accordance with a process reasonably determined by the RIT-D proponent, if the proposed preferred option has the potential to, or is likely to, have an adverse impact on the quality of service experienced by consumers of electricity, including:[326]
  - anticipated changes in voluntary load curtailment by consumers of electricity; or
  - anticipated changes in involuntary load shedding and customer interruptions caused by network outages.
- The consultation period on the draft project assessment report must not be less than six weeks from the publication of the report.[327]

Exemption from the draft project assessment report:

- A RIT-D proponent is not required to prepare and publish a draft project assessment report if:[328]
  - the RIT-D proponent has determined that a non-network options report is not required and has published a notice to that effect; and
  - the estimated capital cost of the proposed preferred option is less than $10 million (as varied in accordance with a cost threshold determination).

Final project assessment report:

- As soon as practicable at the end of the consultation period on the draft project assessment report, the RIT-D proponent must, having regard to any submissions received on the draft project assessment report, publish a final project assessment report.[329]

325 Draft clause 5.17.4(k).

326 Draft clause 5.17.4(l).

327 Draft clause 5.17.4(m).

328 Draft clause 5.17.4(n).

329 Draft clause 5.17.4(o).

- If the RIT-D project is exempt from the draft project assessment report on the basis of a RIT-D proponent having determined that a non-network options report is not required and the estimated capital cost of the proposed preferred option is less than $10 million, the RIT-D proponent must publish the final project assessment report as soon as practicable after the publication of the notice that a non-network options report is not required.[330]

- At the same time as publishing the final project assessment report, a RIT-D proponent that is a DNSP must notify persons on its demand side engagement register of the reports publication.[331]

- The final project assessment report must set out:

  - if a draft project assessment report was prepared:[332]

    - the matters detailed in the draft project assessment report; and

    - a summary of any submissions received on the draft project assessment report and the RIT-D proponent's response to each submission;

  - if no draft project assessment report was prepared, the matters required to be included in the draft project assessment report.[333]

- If the estimated capital cost of the preferred option is less than $20 million (as varied in accordance with a cost threshold determination), the DNSP may discharge its obligations to publish its final project assessment report by including it as part of its DAPR (where the RIT-D proponent is a DNSP) or its TAPR (where the RIT-D proponent is a TNSP).[334]

Re-application of the RIT-D in certain circumstances:

- Unless otherwise determined by the AER, a RIT-D proponent must reapply the RIT-D to a RIT-D project if:[335]

  - a RIT-D proponent has published a final project assessment report in respect of a RIT-D project;

  - an NSP still wishes to undertake the RIT-D project to address the identified need; and

330 Draft clause 5.17.4(p).

331 Draft clause 5.17.4(q).

332 Draft clause 5.17.4(r)(1).

333 Draft clause 5.17.4(r)(2).

334 Draft clause 5.17.4(s).

335 Draft clause 5.17.4(t).

- there has been a material change in circumstances which, in the reasonable opinion of the RIT-D proponent means that the preferred option identified in the final project assessment report is no longer the preferred option.

- When making a determination above, the AER must have regard to the credible options (other than the preferred option) identified in the final project assessment report and the change in circumstances identified by the RIT-D proponent.[336]

RIT-D application guidelines:

- The AER must develop and publish guidelines for the operation and application of the RIT-D (RIT-D application guidelines) in accordance with the distribution consultation procedures.[337]

- The RIT-D application guidelines must give effect to and be consistent with the relevant RIT-D rules and must provide guidance on:[338]

  - the operation and application of the RIT-D;

  - the process to be followed in applying the RIT-D; and

  - how disputes raised in relation to the RIT-D and its application will be addressed and resolved.

- The RIT-D application guidelines must provide guidance and worked examples as to:

  - how to make a determination under the non-network screening process;[339]

  - what constitutes a credible option;[340]

  - the classes of market benefits to be considered;[341]

  - the acceptable methodologies for valuing the market benefits of a credible option;[342]

336 Draft clause 5.17.4(u).

337 Draft clause 5.17.2(a).

338 Draft clause 5.17.2(b).

339 Draft clause 5.17.2(c)(1).

340 Draft clause 5.17.2(c)(2).

341 Draft clause 5.17.2(c)(3).

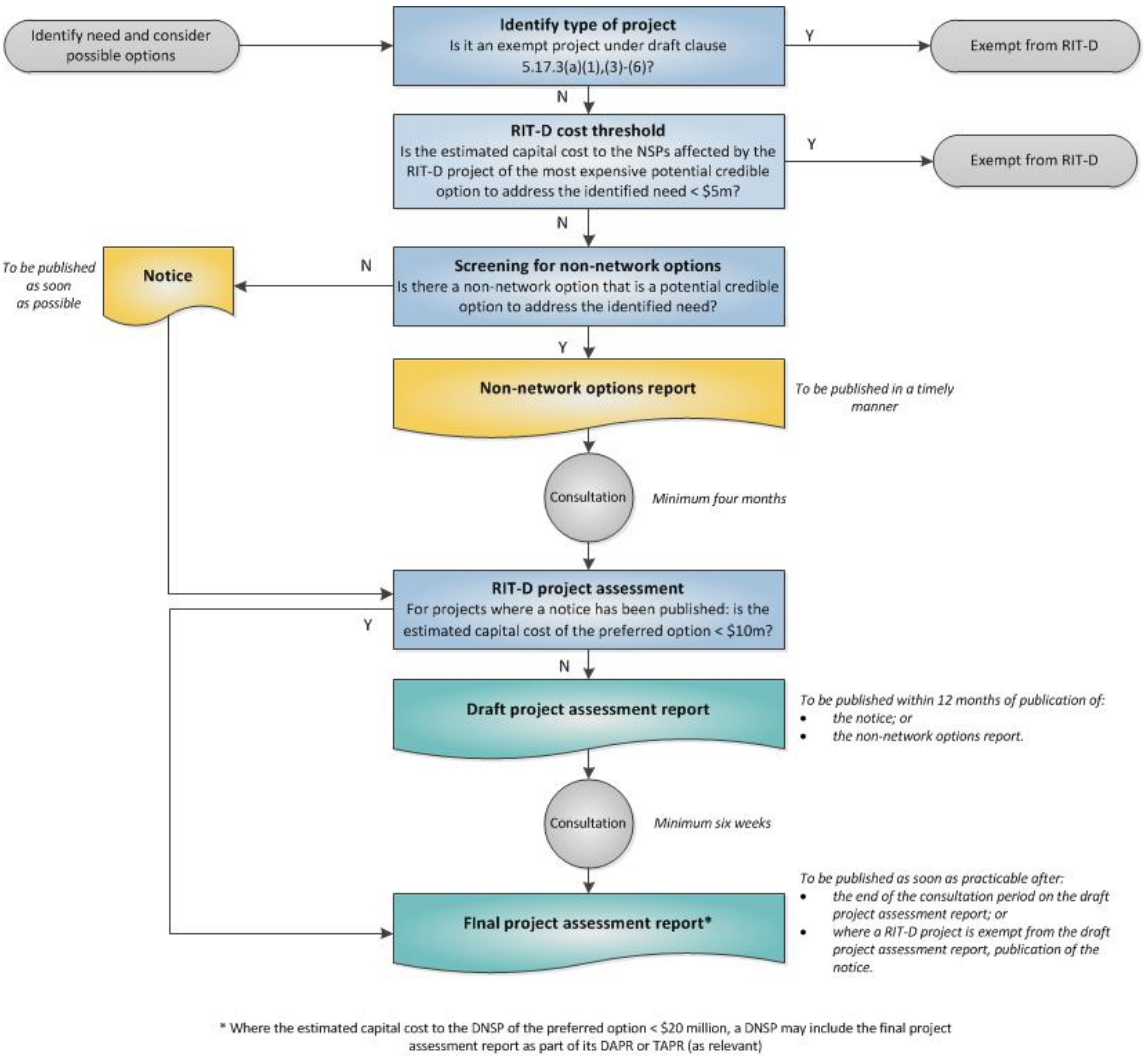
342 Draft clause 5.17.2(c)(4).

- acceptable methodologies for valuing the costs of a credible option;[343]
- the appropriate approach to undertaking a sensitivity analysis;[344]
- the appropriate approaches to assessing uncertainties and risks;[345] and
- what may constitute an externality under the regulatory investment test for distribution.[346]

- The AER must develop and publish the RIT-D and RIT-D application guidelines by the date that is nine months after the commencement of the rule and there must be a RIT-D and RIT-D application guidelines in force at all times after that date.[347]
- The AER may, from time to time, amend or replace the RIT-D and RIT-D application guidelines in accordance with the distribution consultation procedures provided that the AER publishes any amendments to, or replacements of, the RIT-D or RIT-D application guidelines at the same time.[348]
- The AER may publish the RIT-D and RIT-D application guidelines and the RIT-T and RIT-T application guidelines in a single document.[349]

343 Draft clause 5.17.2(c)(5).
344 Draft clause 5.17.2(c)(6).
345 Draft clause 5.17.2(c)(7).
346 Draft clause 5.17.2(c)(8).
347 Draft clause 5.17.2(d).
348 Draft clause 5.17.2(e).
349 Draft clause 5.17.2(h).

Figure 9.1 RIT-D process



9.3 Commission's assessment

The Commission has analysed and assessed the policy and drafting issues arising from the rule change request in respect of the proposed RIT-D process. Outlined below is the Commission's assessment of this aspect of the draft rule, including the reasons why it considers this aspect of the draft rule better meets the NEO then the proposed rule.

9.3.1 RIT-D principles

Amalgamation of the reliability and market benefits limbs

The draft rule sets out a design for the RIT-D which amalgamates the reliability and market benefits limbs of the current regulatory test into a single cost-benefit framework. All projects for which the RIT-D is applicable would be assessed under this framework.

The Commission considers that there are significant advantages in having a single cost-benefit project assessment process that can be applied consistently across all

prospective projects, irrespective of the driver for the investment. Importantly, the single process will allow all projects to be assessed against local reliability standards as well as against their ability to maximise benefits to the broader market. This will help to ensure that the NSP leading a RIT-D assessment identifies the most efficient investment option rather than simply the least-cost investment option to address a network issue. This will facilitate efficient decision making by NSPs and promote efficient investment in networks.

Assessment of market benefits and cost

In applying the RIT-D, the draft rule requires RIT-D proponents to consider all applicable market benefits and costs for each credible option. However, while the draft rule requires the quantification of all applicable costs, it provides RIT-D proponents with the option of quantifying any applicable market benefits.

Providing flexibility in the assessment of market benefits recognises that, in many cases, RIT-D projects will tend to have limited market benefits. The Commission considers that this design will help to ensure that the project assessment process is fit for purpose for each RIT-D project and that the regulatory burden on the RIT-D proponent from carrying out the requirements of the RIT-D is proportionate to the potential benefits of the assessment process.[350]

9.3.2 RIT-D scope

RIT-D cost threshold

The purpose of the RIT-D cost threshold is to ensure that the administrative burden on RIT-D proponents from conducting the RIT-D process remains proportionate to its potential benefits. It achieves this by providing a dollar amount below which the RIT-D would not be applied.

The draft rule sets the RIT-D cost threshold at $5 million and requires this to be applied to the estimated capital cost (to the NSPs affected by the RIT-D project) of the most expensive potential credible option.[351] The Commission considers that this threshold provides the appropriate balance between minimising the regulatory burden placed on NSPs in conducting the RIT-D process, and ensuring that the appropriate range of projects are subject to a robust and transparent economic assessment.

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350 In addition, the Commission considers any risk that a RIT-D proponent may not quantify market benefits where they are material, or may only assess those market benefits which validate their preferred option, would be reduced to some extent by requiring the proponent to set out their reasoning for their preferred option in the project assessment reports. In addition, the draft rule will provide stakeholders with the ability to raise disputes in relation to a RIT-D proponents application of the RIT-D. This should also provide a discipline on relevant NSPs to consider and quantify any applicable market benefits where these are material or where they may alter the outcome of the RIT-D assessment.

351 As noted above, 'potential credible option' is defined as an option the RIT-D proponent reasonably considers has the potential to be a credible option based on its initial assessment of the identified need.

It is intended that the RIT-D cost threshold be applied by relevant NSPs early in the project planning process to determine whether or not or specific project would be subject to the RIT-D. At this stage in the process, a RIT-D proponent would not be expected to have determined whether or not a potential investment option is a credible option as defined under section 5.15.2 of the draft rule. However, a RIT-D proponent would be expected to have formed an initial view on the likelihood of potential options being classified as credible options. It is to this initial list of potential credible options to which the RIT-D cost threshold should be applied.[352]

The most expensive technically and economically feasible option

The proposed rule provided for the cost threshold level to be applied to the most expensive option which is both technically and economically feasible. The terms 'technically and economically feasible' were originally included in the rules for the RIT-T cost threshold to address a concern raised by Grid Australia during the AEMC's National Transmission Planning Arrangements review that it would always be possible to conceive of an extremely high cost option for addressing an identified need.[353] In the absence of qualification, Grid Australia was concerned that every transmission project would be subject to the RIT-T, thereby rendering the RIT-T cost threshold ineffective.

While the rules do not define technically feasible or economically feasible, the AER provides general guidance on the meaning of these terms in its RIT-T application guidelines.[354] In summary, the inclusion of these terms in the RIT-T rules was intended to clarify that the RIT-T cost threshold would not be expected to be applied to potential options which are not comparable in cost to other potential options to address an identified need. In effect, this qualification would avoid the RIT-T process being triggered by a potential investment option which, based on its estimated cost, would be unlikely to be identified as a preferred option in the RIT-T assessment.

Despite the same approach being proposed for adoption in the RIT-D, a number of stakeholders expressed concern that the terms 'technically and economically feasible' were open to interpretation and, in line with the concerns raised by Grid Australia in the context of the RIT-T, would lead to almost every project being subject to the RIT-D. These stakeholders suggested amending the approach to applying the RIT-D cost

352 In effect, the application of the threshold would be a desktop exercise requiring DNSPs to exercise a degree of judgement, supported by credible evidence.

353 AEMC 2008, *National Transmission Planning Arrangements*, Draft Report, 2 May 2008, Sydney, p. 37.

354 In relation to an investment option being economically feasible, page 6 of the RIT-T application guidelines states: "as general guidance, the AER considers that an option is likely to be economically feasible where its estimated costs are comparable to other credible options which address the identified need. One important exception to this general guidance applies where it is expected that a credible option or options are likely to deliver materially higher market benefits. In these circumstances the option may be "economically feasible" despite the higher expected cost."

threshold to the least expensive technically feasible option or, alternatively, to a DNSPs preferred option.[355]

While the Commission recognises that further clarification regarding the application of the RIT-D cost threshold may be beneficial, for a number of reasons it does not consider that amending the rule in the manner suggested above is the best means of addressing stakeholder concerns.

First, changing the approach to applying the RIT-D cost threshold would require reconsideration of whether the $5 million cost threshold level remains appropriate. This is because making a change to the application of the cost threshold without making a corresponding change to the cost threshold level would upset the balance currently achieved by the $5 million cost threshold being applied to the most expensive economically and technically feasible option.[356] As noted above, the Commission is satisfied that the RIT-D cost threshold provides the appropriate balance between ensuring the appropriate range of projects are subject to robust economic assessment, and the timing and resources required to conduct the process.

Second, having considered submissions in detail, the Commission notes that the concerns raised by stakeholders are a direct consequence of the interpretation of the terminology used in the proposed rule, rather than a fundamental issue with the RIT-D cost threshold settings themselves.

On this basis, the draft rule includes a change to the terminology used to describe the approach to applying the RIT-D cost threshold with the aim of better clarifying the intent. Specifically, reference to 'the most expensive option which is technically and economically feasible' has been replaced with reference to 'the most expensive potential credible option'.

The Commission considers that it would be more meaningful to relate the RIT-D cost threshold to the subset of potential options to which the RIT-D must be applied (that is, to the group of potential 'credible options' as defined under section 5.15.2 of the draft rule). Consequently, an extremely high cost option which is unlikely to deliver materially higher market benefits compared to other potential options would not be expected to be included in the list of potential options to which the RIT-D cost threshold level would be applied.

The term 'potential' has been included to recognise that, at this stage in the RIT-D process, a RIT-D proponent is not expected to have carried out the necessary analysis to enable it to have fully formed a view on which options are credible options for the

355 Essential Energy also suggested that the provision should relate to the 'credible option' definition and use. As explained later in this section, the Commission considers there is merit in this suggestion.

356 The RIT-D cost threshold comprises two parts: (1) the threshold level ($5 million) and (2) the approach to applying the threshold level ('the most expensive option which is technically and economically feasible'). The threshold level is intended to reflect the point at which the potential benefits of performing the RIT-D are outweighed by the costs. The approach should then be set to ensure all intended projects are captured.

purpose of assessment under the RIT-D. However, a RIT-D proponent is expected to have formed at least an initial view on the possibility of potential options being both technically and commercially feasible, and likely to be implemented in a timely manner. It is to this initial list of potential credible options that the RIT-D cost threshold should be applied.

A key assumption made in preparing the draft rule is that an option that is determined to be 'commercially feasible' must also be 'economically feasible' (and vice versa). As such, the approach to applying the RIT-D cost threshold is the same as the approach used in applying the RIT-T cost threshold. The use of different terminology in the context of the RIT-D rules (compared to the RIT-T) is intended only to address the concerns of DNSPs that, as drafted, the approach to applying the RIT-D cost threshold was not sufficiently clear.

Projects subject to the RIT-D

While it is intended that the RIT-D be applied to all projects involving expenditure in respect of a network, there are several types of projects which would be exempt from the RIT-D. As noted in section 9.1.1 above, these include projects which relate to: urgent or unforeseen network issues; negotiated, alternative control and unclassified services; replacements and refurbishment expenditure; and connection assets.[357]

It is appropriate to exempt these projects from the scope of the RIT-D on the basis that the benefits to be gained from their assessment under the RIT-D would, in most cases, be unlikely to outweigh the costs, risks or regulatory burden on relevant NSPs from applying the RIT-D process. For example, including replacement and refurbishment expenditure within the scope of the RIT-D may impose a disproportionate regulatory burden on (in particular) DNSPs due to the large volume of replacements undertaken by DNSPs and the limited alternatives for replacement investments. The Commission considers that to require NSPs 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 would be unlikely to yield alternative solutions which may be more efficient.

In submissions to the consultation paper, a number of stakeholders advocated for the exclusion of several other classes of distribution projects from the scope of RIT-D.[358] Several stakeholders also requested clarification as to whether other certain types of investment projects would or would not be considered to be within the scope of the RIT-D.[359]

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357 In addition, projects identified through the joint planning process which meet the definition of a 'RIT-T project' would also be exempt from the RIT-D.

358 ENA, Consultation Paper submission, pp. 16-17; Ergon Energy, Consultation Paper submission, pp. 5, 17; ETSA Utilities, Consultation Paper submission, pp. 6-8.

359 Energex, Consultation Paper submission, pp. 7, 10, 18; Ergon Energy, Consultation Paper submission, pp. 15-16; ETSA Utilities, Consultation Paper submission, pp. 6-8; ENA, Consultation Paper submission, p. 15; Ausgrid, Consultation Paper submission, pp. 6-8

Having considered the concerns of stakeholders, the Commission considers there is benefit in clarifying the types of project to which the RIT-D is intended to apply, and noting the several exceptions. For the purposes of this clarification, DNSPs (and TNSPs where a TNSP has been identified as the lead party for a RIT-D project) would be required to apply the RIT-D to all projects which meet the following criteria:

- the driver for the investment is the need to address an issue on a distribution network (or a transmission network if the need is identified under the joint planning process); and
- the expenditure will be made by an NSP; and
- the expenditure will be (fully or partially) recovered from all users of the network; and
- the RIT-D project meets the RIT-D cost threshold.

Exemptions would then be provided for:

- RIT-D projects required to address an urgent and unforeseen network issue; and
- RIT-D projects related to the replacement and refurbishment of assets (except where that investment includes an augmentation to the network with an estimated capital cost greater than $5 million); and
- projects where the identified need is identified through the joint planning process and to which the RIT-T is applicable.

Under the proposed rule, projects which include the possibility of investment in dual function assets will be subject to the RIT-D (unless subject to the RIT-T under the joint planning arrangements). The treatment of dual function assets is discussed further in sections 5.3.2 and 8.3.4 of this draft determination.

The Commission notes that it is not the intention to include in the rules an exhaustive list of all circumstances in which the RIT-D would apply. Apart from the 'criteria' listed above, further clarification could be included in the AER guidelines if the AER and stakeholders consider that may be helpful.

Urgent and unforeseen network issue

In submissions to the consultation paper, several stakeholders expressed concern in relation to the proposed definition of an urgent and unforeseen network issue. The proposed rule states that a distribution investment will be considered to address an urgent and unforeseen network issue if:

- it is necessary that the proposed distribution investment be operational within six months of the NSP identifying the identified need; and
- the event or circumstances causing the identified need was not reasonably foreseeable by, and was beyond the reasonable control of, the DNSP; and

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

In particular, stakeholders expressed concern in relation to the requirement for an investment to be operational within six months of the need being identified, in order to qualify for the exemption.[360]

While the Commission acknowledges these concerns, it considers that the definition of urgent and unforeseen network issue as set out in the proposed rule is appropriate (subject to several minor amendments to the terminology to recognise the requirements of the joint planning process). The purpose of providing exemptions for projects which are initiated to address urgent and unforeseen network issues is to ensure that the RIT-D project assessment process does not reduce or adversely impact the ability for DNSPs (or TNSPs, where applicable) to make necessary but unanticipated investments. It is intended that this exemption be used rarely and only where the need to undertake an investment results from extenuating circumstances, such as extreme weather. It is not intended that the exemption be used by NSPs in the place of accurate and timely planning practices.

For this reason, the Commission has determined not to deviate from the requirements in the proposed rule in line with the proposals put forward by stakeholders.

9.3.3 RIT-D procedures

Screening for non-network options

In order to ensure the requirements of the RIT-D are fit for purpose and proportionate to their potential benefits, the draft rule includes a screening process ("non-network screening process") designed to tailor the consultation and reporting requirements to each RIT-D project.

The draft rule achieves this by providing an exemption from the requirements to prepare and publish a non-network options report where a RIT-D proponent determines that there will not be a non-network option which is a potential credible option to address the identified need. Where a RIT-D proponent makes such a determination (based on the information available to it at the time), the RIT-D proponent will not be required to consult with interested stakeholders to investigate potential non-network options further.

By providing an avenue for straightforward RIT-D projects with limited opportunities for non-network solutions to bypass consultation on non-network options, the non-network screening process will help to balance the costs to relevant NSPs of applying the RIT-D process with the potential benefits to the market of ensuring all possible options are identified and considered.

360 ENA, Consultation Paper submission, p. 16; Ergon Energy, Consultation Paper submission, p. 18; Victorian DNSPs, Consultation Paper submission, p. 5; Essential Energy, Consultation Paper submission, p. 7; ETSA Utilities, Consultation Paper submission, pp. 6-8.

'Technically feasible' non-network options

In order for the screening process to be effective, the draft rule must be able to identify the subset of projects which would be unlikely to benefit from additional consultation and reporting. In this case, the intended subset of RIT-D projects are those where there is no material potential for a non-network option to provide a feasible alternative to network investment.

The proposed rule included the concept of the specification threshold test, which would have required DNSPs to assess:

- the reasons for a proposed distribution investment, including the assumptions used in identifying the identified need; and
- technically feasible non-network options that could either defer or remove the need for a proposed distribution investments to address the identified need.

In submissions to the consultation paper, a number of stakeholders expressed concern that the drafting of the proposed rule failed to capture the original intent of the initial screening test. Specifically, these stakeholders were concerned that the requirement to assess 'technically feasible' non-network options would result in all distribution projects meeting the screening test criteria, therefore rendering it ineffective as a means of providing flexibility in the RIT-D process.[361]

As an alternative, these stakeholders suggested that the phrase 'technically feasible non-network options' be replaced with reference to 'credible non-network options'. In effect, this change would provide for the streamlining of the RIT-D process for projects where, following the screening test assessment, a DNSP was unable to identify a credible non-network option (i.e. a non-network option which was commercially and technically feasible, and able to be implemented in a timely manner).

While the Commission considers there may be merit in linking the screening process directly to credible non-network options (rather than to technically feasible non-network options), it is concerned that without further qualification, the amendments suggested by stakeholders will also fail to achieve the original intent.

First, the Commission notes that the screening process is intended to be a desk-top exercise, undertaken early in the planning process and based on information available to the DNSP (or TNSP, where relevant) at the time of undertaking the exercise. At this stage, the RIT-D proponent would not be expected to have all the information necessary, nor have carried out the required analysis, to have formed a definitive view on which non-network options (of those identified by the RIT-D proponent) are 'credible options' as defined under section 5.15.2 of the draft rule.

361 This is because it would always be possible to identify at least one 'technically feasible' non-network option (irrespective of whether a technically feasible option was commercially and/or economically feasible).

Second, at this stage of the screening process, non-network providers would not yet have been provided with a formal opportunity to provide input into the project assessment process. Requiring the RIT-D proponent to form a view on credible non-network options ahead of formal consultation carries a risk that efficient non-network options may be overlooked.

With that said, the Commission notes that linking the screening process to 'credible non-network options' will allow RIT-D proponents to draw on any information gathered through earlier engagement with non-network providers on the technical and commercial feasibility, and timeliness, of particular non-network options. This will enable them to take a more informed view on the material potential for non-network solutions and should encourage RIT-D proponents to engage with non-network providers earlier in the process and on an ongoing basis. This is particularly important where a RIT-D proponent is a DNSP, given the demand side engagement obligations included in the draft rule.[362]

On this basis, the draft rule does not include the concept of the specification threshold test and instead includes a requirement for the RIT-D proponent to consider, for each project for which the RIT-D process is applicable, whether a non-network option will be a potential credible option to address the identified need. The Commission considers that this change will provide for a more targeted screening process to identify those projects where there is material potential for non-network options as an alternative to network investment.

Non-network options report

Where it is determined for a RIT-D project that a non-network option is a potential credible option, the RIT-D proponent would be required to consult on potential non-network options to address the identified need through the preparation and publication of a non-network options report. This report will provide a formal mechanism for RIT-D proponents to gather information from market participants on potential non-network solutions which may provide credible alternatives to network investment.

The purpose of the non-network options report is twofold:

1. to provide information to non-network proponents to assist them in considering, developing and proposing viable non-network options; and

2. to seek information from market participants and other interested parties on potential credible non-network options, including on the range of materially relevant costs and market benefits.

362 This is because the screening test will allow for the fast tracking of a greater number of distribution projects where DNSPs does not reasonably expect that a non-network solution will provide a credible alternative to a network solution. In this instance, DNSPs would simply be required to publish a notification to this effect with supporting reasons and the distribution project would proceed to the project assessment stage without being subject to additional consultation and reporting.

For the report to be useful and meet these objectives, it must provide relevant information that would be of assistance to market participants and interested parties, including non-network proponents, in preparing useful and informative non-network proposals and/or submissions.

The draft rule therefore sets out the key information required to be included in the non-network options report. This includes: a description of the identified need; the relevant annual deferred augmentation charge associated with the identified need; the technical characteristics that a non-network option would be required to meet; and a summary of potential non-network options which may address the identified need, as identified by the RIT-D proponent.

In addition to the required content specified in the draft rule, a RIT-D proponent would also be expected to seek submissions on any aspect of a RIT-D project where additional information may assist in its application of the RIT-D. For example, further information may be requested on:

- *potential non-network options*: whether there are any alternative non-network solutions not already identified by the RIT-D proponent;
- *non-network credible options*: in respect of the potential non-network solutions identified, whether these are commercially and technically feasible at the scale required, and/or likely to be available in a similar timeframe to the network options; or
- *inputs into the RIT-D assessment:* in respect of the non-network credible options already identified by a RIT-D proponent, the estimated costs and possible market benefits of each credible option.

It is important to note that the draft rule does not prevent relevant NSPs from providing additional information to, or requesting additional information from, stakeholders, in the non-network options report.

The Commission considers the draft rule is likely to promote greater consultation with relevant stakeholders, which should help ensure that all potential non-network options are identified, and that RIT-D proponents are better informed on the costs and market benefits associated with a proposed investment. This process should reduce the risk that efficient non-network options are overlooked in the project assessment process, and thus improve the application of the RIT-D assessment.

Consultation on network options

If implemented, the proposed rule would have required DNSPs to consult on potential network options (in addition to potential non-network options) as part of the proposed project specification report. However, in shifting the focus of the report from project specification to the further investigation of potential non-network options, the Commission has determined not to require a RIT-D proponent to consult on potential network options as part of this process.

In addition, the Commission considers that it would be inconsistent to require a RIT-D proponent to consult on network options for RIT-D projects subject to this stage of the RIT-D process, while not requiring equivalent consultation for RIT-D projects exempt from this stage of the process.

With that said, while the draft rule does not require a RIT-D proponent to consult on potential network options, they may wish to do so in certain circumstances.

Draft project assessment report

Within 12 months (or any longer time period as agreed in writing by the AER) of either: (1) the end of consultation on the non-network option report; or (2) where a non-network options report is not required, the publication of a notice to this effect, a RIT-D proponent must prepare and publish a draft project assessment report setting out certain specified information.[363]

The purpose of the draft project assessment report is to provide greater transparency in respect of a RIT-D proponent's decision making process, including in respect of its consideration and assessment of the range of credible options, and the identification of the preferred option. The Commission considers this will promote greater consultation with, and encourage participation by, interested stakeholders in the network planning process.

The draft rule also requires that interested stakeholders be provided with a minimum period of six weeks within which to make a submission to the draft project assessment report. The Commission considers that specifying a minimum timeframe for consultation will provide relevant NSPs with greater certainty regarding the impact of the RIT-D process on the timing of an investment, thereby assisting those NSPs to better manage any risk associated with the RIT-D process.

Exemptions from preparing a draft project assessment report

For RIT-D projects where: (1) a RIT-D proponent is not required to publish a non-network options report; and (2) where the estimated capital cost of the proposed preferred option is less than $10 million, the draft rule provides an exemption from the requirement to prepare and publish a draft project assessment report.[364]

The Commission considers that providing such an exemption will help to prevent straightforward projects from being unnecessary delayed by the project assessment process. It will also reduce the regulatory burden faced by proponents of the RIT-D in conducting the test.

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363 The required content of the draft project assessment report is set in draft clause 5.17.4(I). This includes (among other things): a description of each credible option assessed; quantification of applicable costs and, where relevant, applicable market benefits; the results of the net present value analysis of each credible option; and the identification of the proposed preferred option.

364 For such investments, DNSPs would be required to publish a final project assessment report following publication of the notice required under draft clause 5.17.4(d).

Further, the Commission considers that the draft rule provides sufficient clarification and obligations to prevent this exemption from being inappropriately used, including providing stakeholders with the avenue to raise a dispute where necessary.

Final project assessment report

As soon as practicable following either: (1) the end of consultation on the draft project assessment report; or (2) where a non-network options report is not required, the publication of a notice, a RIT-D proponent must publish a final project assessment report. The draft rule sets out the information to be included within the final report.[365]

In line with the Commission's views in relation to the draft project assessment report, the obligation to publish a final project assessment report will further increase transparency in respect of a RIT-D proponent's decision making process. This will promote greater consultation with, and encourage participation by, interested stakeholders in the network planning process.

In addition, the draft rule provides that a RIT-D proponent may publish a final project assessment report as part of its DAPR (where the RIT-D proponent is a DNSP) or its TAPR (where the RIT-D proponent is a TNSP) where the preferred option has an estimated capital cost of less than $20 million. The Commission considers that providing RIT-D proponents with the opportunity of publishing a final project assessment reports within the relevant APR will decrease compliance costs for relevant NSPs while ensuring that the final project assessment report for more significant projects are published in a timely manner.[366]

9.3.4 Re-application of the RIT-D

In its submission to the consultation paper, Energex sought clarification around the circumstances in which a DNSP would be expected to reapply the RIT-D.[367] In addition, the AER requested that the Commission consider whether DNSPs should be required to reapply the RIT-D in certain circumstances, including where a significant period of time has elapsed since completion of an original assessment.[368]

Having considered these submissions in detail, the Commission has concluded that it would be reasonable and prudent to require a RIT-D proponent to reapply the RIT-D in full and consult with stakeholders in circumstances where it is no longer likely that an original RIT-D assessment identifies the most efficient option. The draft rule therefore includes a provision which makes clear that (unless otherwise determined by the AER) a RIT-D proponent would be expected to reapply the RIT-D where there is a

365 The information requirements differ depending on whether a RIT-D proponent has prepared and published a draft project assessment report. See draft clause 5.17.4(r).

366 The Commission considers that DNSPs are likely to have an incentive to publish their final project assessment reports as soon as possible, given the possibility that a dispute may be raised and a project delayed while the dispute resolution process is conducted.

367 Energex, Consultation Paper submission, p. 18.

368 AER, Consultation Paper submission, p. 7.

material change in circumstances which, in the RIT-D proponent's reasonable opinion, means that the preferred option identified in the original RIT-D assessment is no longer the preferred option.[369] In making a determination, the AER would be expected to have regard to the credible options and the details of the change in circumstances.

The Commission considers that further clarity on this issue will help to reduce uncertainty for RIT-D proponents as to when the RIT-D would need to be reapplied, while ensuring the integrity of the RIT-D project assessment process is maintained.[370]

9.3.5 AER review and audit activities

In order to determine whether or not a DNSP had given due consideration to non-network options in the planning process, the proposed rule provided the AER with specific audit and review powers to: (1) review a DNSP's policies and procedures to determine if non-network options have been duly considered; and (2) audit projects which have been identified by a RIT-D proponent as not meeting the RIT-D cost threshold. These proposals were intended to provide an increased incentive for DNSPs to fully consider non-network solutions for all investment decisions.

However, the AER already has a number of functions and powers set out in legislation in relation to monitoring, investigating and enforcing compliance with various aspects of the national energy framework, including with the NER. The AER's compliance and enforcement strategy sets out the range of mechanisms used to monitor compliance, which include undertaking audits to assess participants' compliance with specific obligations. In addition, the AER issues quarterly compliance reports setting out the results of its monitoring and enforcement activities.

Therefore, in line with the views of the majority of stakeholders,[371] the Commission considers that the AER's existing functions and powers sufficiently capture the review and audit activities proposed for inclusion in the rules. In addition, the Commission does not consider it is appropriate for the rules to mandate and prioritise the AER's compliance and enforcement activities. The AER's approach to compliance is based on a risk assessment of the impact and probability of breaches of particular obligations. It also varies over time as needed and in light of changes in the market and other matters. This approach is set out in the AER's compliance and enforcement statement of approach document, available on its website.[372]

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369 The Commission notes that a material change in circumstance may include regulatory changes which occur after the original RIT-D assessment and which results in the preferred option no longer being considered technically feasible, and therefore no longer being the preferred option.

370 There is currently no equivalent provision in the NER in respect of the re-application of the RIT-T in certain circumstances.

371 Ergon Energy, Consultation Paper submission, p. 19; Energex, Consultation Paper submission, p. 18; Victorian DNSPs, Consultation Paper submission, p. 16; Ausgrid, Consultation Paper submission, pp. 6-8; Endeavour Energy, Consultation Paper submission, p. 9; Essential Energy, Consultation Paper submission, p. 7; Aurora Energy, Consultation Paper submission, p. 8.

372 AER 2010, *Compliance and Enforcement, Statement of Approach*, December 2010.

For this reason, the draft rule does not include additional powers for the AER to review and audit DNSPs activities regarding the consideration of non-network options.

9.3.6 RIT-D and RIT-D application guidelines

At the same time the AER publishes the RIT-D, the AER must also publish guidelines on the operation and application of the RIT-D, including information on how disputes in relation to the application of the RIT-D would be addressed and resolved by the AER (RIT-D application guidelines).

The draft rule sets out the information that the AER would be required to provide in the RIT-D application guidelines. This includes guidance and worked examples on various aspects of the test, including: what constitutes a credible option; acceptable methodologies for valuing the market benefits and costs of a particular credible option; what may constitute an externality under the RIT-D; the appropriate approach to undertaking a sensitivity analysis; and the appropriate approaches to assessing uncertainties and risks. This information is intended to assist NSPs in applying the RIT-D in accordance with the rules.

The RIT-D application guidelines are intended to work together with the test and the RIT-D principles (set out in the rules) to effectively govern the application of the RIT-D. The Commission considers that the draft rule strikes the appropriate balance between the rules prescribing the framework necessary to achieve the objectives of the RIT-D, and the AER developing and administering the test, and ensuring compliance with the rules.

The draft rule also provides the AER with the option of publishing the RIT-D and RIT-D application guidelines together with the RIT-T and RIT-T application guidelines as a single document. This will provide for greater efficiency in the AER's processes and may improve consistency between the RIT-T and RIT-D.

In addition, the draft rule provides the AER with a period of nine months following the commencement of the rule to develop and publish the RIT-D and RIT-D application guidelines. This timeframe is discussed further in section 11.3.3 of this draft determination.

9.4 Rule making test

The Commission is satisfied that the RIT-D arrangements as set out in the draft rule will, or are likely to, better contribute to the achievement of the NEO relative to the proposed rule. The draft rule is likely to promote efficient investment in distribution networks for the long term interests of consumers of electricity through:

- promoting greater consultation with stakeholders which should help to ensure that all relevant investment options are identified, considered and quantified;
- improving consistency and transparency of distribution investment assessments, thereby promoting more efficient decision making by NSPs; and

- facilitating a more strategic assessment of projects which should optimise decision making and improve the efficiency of the distribution assessment process.

The Commission also considers the draft rule will promote good regulatory practice by balancing the appropriate range of projects subject to a robust economic assessment and the timing and resources required to conduct the planning process.

10 Dispute resolution process

This chapter sets out the Commission's views in relation to the dispute resolution process, having regard to the views of stakeholders in submissions to the consultation paper. This chapter is structured as follows:

- section 10.1 describes the proposed dispute resolution process as proposed by the proponent and summarises stakeholder responses to the consultation paper on this matter;
- section 10.2 sets out the Commission's proposed amendments to the proposed rule and a description of the draft rule on this matter;
- section 10.3 provides a summary of the Commission's analysis and assessment of the dispute resolution process draft rules; and
- based on the Commission's assessment in section 10.3, section 10.4 sets out the Commission's conclusions on this matter.

10.1 Proposed rule

10.1.1 Description of the proposed rule

The rule change request proposes to introduce a specific dispute resolution process for the RIT-D which has been based on the dispute resolution process for the RIT-T. The proposed rule specifies that:

- the dispute resolution process would be a compliance only review and only apply to a DNSP's application of the RIT-D against the requirements in the rules;
- the process would apply to all investments which are subject to the RIT-D and would cover all stages and decisions made by DNSPs when applying the test;
- the dispute resolution process would be conducted by the AER;
- registered participants, AEMO, the AEMC, connection applicants, intending participants, interested parties[373] and non-network providers would be able to dispute matters set out in a DNSP's final project assessment report within 30 days of the publication of the final project assessment report;

373 The proposed rule sought to amend the definition of 'interested party' as currently defined in Chapter 10 of the NER as follows: "a person including an end user or its *representative* who, in the AER's opinion, has, or identifies itself to the AER as having the potential to suffer a material and adverse market impact from the proposed *transmission investment* or *distribution investment* (as the case may be) that is the *preferred option* identified in the *project assessment conclusions report* or the *final project assessment report* (as the case may be)."

- within 40 to 100 days of receiving the dispute notice (depending on the complexity of the dispute), the AER would either:
  - reject the dispute where it determines that the grounds for the dispute are invalid, misconceived or lacking in substance; or
  - make a determination on the dispute to direct the DNSP to amend its final project assessment report if:
    - the DNSP has not correctly applied the RIT-D in accordance with the rules; or
    - the DNSP has made a manifest error in its calculations; and
- in making a determination on a dispute, the AER would specify the time frame for the DNSP to amend its final project assessment report.

The proposed rule would also allow the AER to grant exemptions from the dispute resolution process if it considers the need for the relevant distribution investment to proceed outweighs the benefits from conducting the dispute resolution process.

Current arrangements

Currently, disputes regarding the application of the regulatory test by DNSPs must be resolved according to the dispute resolution process in Chapter 8 of the NER. These provisions are general in nature and not tailored to the specific types of disputes that may be raised in relation to distribution planning. Further, the dispute resolution process in Chapter 8 of the NER only applies to disputes between registered participants. There are currently no formal jurisdictional dispute resolution processes for distribution in any of the NEM jurisdictions.

10.1.2 Proponent's view

The rule change request notes that the proposed dispute resolution process is intended to provide greater transparency and clarity regarding how disputes can be resolved and the obligations on disputing parties. The proponent considers that the proposed process would allow disputes to be resolved in a timely manner, ensuring that distribution investments are not unduly delayed.[374]

10.1.3 Stakeholder views

Scope of the dispute resolution process

The ENA, Ergon Energy and the AER were supportive of the proposal to limit the scope of the dispute resolution process to a DNSP's compliance with the RIT-D

374 MCE, Rule Change Request, 30 March 2011.

rules.[375] The ENA considered that a compliance only review would reduce the administrative burden and other costs on DNSPs and the AER, while also reducing the likelihood of unnecessary delays in the assessment of distribution projects.[376]

In relation to the scope of parties eligible to raise a dispute, stakeholders were divided on this issue. Aurora Energy, EnerNOC and Ergon Energy noted support for the proposed scope of parties.[377] However, almost half of the DNSPs who provided a submission considered the proposed scope was too broad and unlikely to prevent vexatious claims being lodged and projects being delayed.[378]

As an alternative, the Victorian DNSPs suggested limiting the scope of potential dispute applicants to connection applicants, AEMO and affected registered participants.[379] The ENA, Energex and Ergon Energy suggested that parties should be prevented from raising a dispute in relation to any issue that could have been raised during consultation on the RIT-D draft project assessment report.[380] Ergon Energy suggested that disputes be disallowed where the party lodging a dispute had not submitted a non-network proposal to the project specification report.[381] Endeavour Energy also suggested limiting the scope of parties to those who made a submission during the consultation period.[382]

While broadly supportive of the classes of parties that could raise a dispute, the AER considered two aspects of the definition of 'interested party' required further clarification.[383] The AER suggested amending references to "identifies itself as having" and "market" in the definition to remove some ambiguity from the proposed rule.

Essential Energy suggested the inclusion of 'relevant and substantive interest' provisions to clarify valid concerns.[384]

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375 ENA, Consultation Paper submission, p. 20; Ergon Energy, Consultation Paper submission, p. 10; AER, Consultation Paper submission, p. 9. ENA, Consultation Paper submission, p. 20.

376 ENA, Consultation Paper submission, p. 20.

377 Ergon Energy's support was premised on adequate controls being in place to minimise vexatious or frivolous disputes. Ergon Energy, Consultation Paper submission, p. 10; Aurora Energy, Consultation Paper submission, p. 8; EnerNOC, Consultation Paper submission, p. 6.

378 Endeavour Energy, Consultation Paper submission, p. 9; Victorian DNSPs, Consultation Paper submission, p. 6; Essential Energy, Consultation Paper submission, p. 8; Ergon Energy, Consultation Paper submission, p. 24; Energex, Consultation Paper submission, p. 18; ENA, Consultation Paper submission, pp. 20-21.

379 Victorian DNSPs, Consultation Paper submission, p. 6.

380 ENA, Consultation Paper submission, pp. 20-21; Ergon Energy, Consultation Paper submission, p. 24; Energex, Consultation Paper submission, p. 18.

381 Ergon Energy, Consultation Paper submission, p .24.

382 Endeavour Energy, Consultation Paper submission, p. 9.

383 AER, Consultation Paper submission, p. 9.

384 Essential Energy, Consultation Paper submission, p. 8.

Exemptions from the dispute resolution process

A significant number of stakeholders expressed support for the proposal to allow the AER to grant exemptions from the proposed dispute resolution process.[385] Energex noted that certain investments may be time sensitive and essential to maintain security of supply and considered the proposal would allow the AER to act in best interests of the market.[386] In addition, Endeavour Energy considered it may be beneficial to include a clause requiring the AER to consider wider community good in relation to time sensitive projects or projects to address security of supply.[387]

In contrast, the AER considered the proposed exemption process was unnecessary and unlikely to improve the proposed dispute resolution process. The AER was of the view that the circumstances in which it may grant an exemption are adequately dealt with in other provisions of the proposed rule. It noted that urgent and unforeseen investments would be exempt from RIT-D, and that the AER would have the power to dismiss disputes if misconceived or lacking in substance.[388]

10.2 Application of the proposed rule and proposed modifications

The draft rule has largely adopted the proposed rules in relation to the dispute resolution process described in section 10.1.1, subject to several policy modifications and a number of amendments to improve and clarify the application of the rule. The manner and reasoning for these amendments are set out below.

10.2.1 Policy amendments

Having regard to the views of stakeholders, and having undertaken its own analysis and review, the Commission has, in the draft rule, made a modification to the proposed rule to improve the application of the rule and better promote the NEO. This modification is as follows:

- *AER granting of exemptions from the dispute resolution process*: the draft rule does not empower the AER to grant an exemption from the dispute resolution process.

385 Ergon Energy, Consultation Paper submission, p. 10; Energex, Consultation Paper submission, p. 19; Victorian DNSPs, Consultation Paper submission, p. 17; Aurora Energy, Consultation Paper submission, p. 9; EnerNOC, Consultation Paper submission, p. 6; Essential Energy, Consultation Paper submission, p. 8; Endeavour Energy, Consultation Paper submission, p. 10.

386 Energex, Consultation Paper submission, p. 19.

387 Endeavour Energy, Consultation Paper submission p. 10.

388 AER, Consultation Paper submission, p. 10.

10.2.2 Amendments to improve clarity and application

The Commission has made a number of amendments to improve and clarify the application of the dispute resolution process in the proposed rule without affecting the principles underlying the proposed rule. These changes are as follows:

- *Definition of 'interested party'*: the draft rule clarifies the definition of 'interested party' to make it clear that, for the purposes of the RIT-T and RIT-D rules, an interested party means a person (including an end user or its representative) who, in the AER's opinion, has the potential to suffer a material and adverse market[389] impact from a proposed transmission or distribution investment which is identified as the preferred option in a RIT-T project assessment consultation report or the RIT-D final project assessment report.

- *Time period for the AER to reject or make a determination on a dispute*: the draft rule clarifies that, where the AER requests additional information from a disputing party or RIT-D proponent at least seven days prior to the expiry of the relevant period, the time period for the AER to either reject or make a determination on a dispute may be extended by the time it takes the relevant party to provide the additional information provided that it does so within 14 days of receipt of the AER's request.

- *Reference to 'business day'*: reference to 'seven business days' and '14 business days' has been omitted from draft clause 5.17.5(h) and replaced with reference to 'seven days' and '14 days'.[390]

- *Other minor changes*: to reflect comments made in submissions to the consultation paper, the draft rule includes a number of other minor drafting amendments. The policy issues log set out in Appendix A, and the legal issues log set out in Appendix B, provide further details of these amendments.

10.2.3 Description of the draft rule

Having regard to the amendments set out above, the key features of the dispute resolution draft rules are described below. Figure 10.1 then sets out a summary of the dispute resolution process.

389 'Market' refers to any of the markets or exchanges described in the NER, for so long as the market or exchange is conducted by AEMO.

390 It is not clear why the proposed rule included a seven and 14 'business' day period. On the basis that reference to 'business' is a drafting error, this has been omitted from the draft rule. The Commission notes that the time period for the equivalent provision in the RIT-T dispute resolution rules now differs from the time period specified in the draft rule.

Box 10.1: Dispute resolution process

- Registered participants, the AEMC, connection applicants, intending participants, AEMC, interested parties[391] and non-network providers may raise a dispute on the grounds that:
  - a RIT-D proponent has not applied the RIT-D in accordance with the rules;[392] or
  - there was a manifest error in the calculations performed by a RIT-D proponent in applying the RIT-D.[393]
- A dispute may not be raised in relation to any matters set out in the final project assessment report which:
  - are treated as externalities by the RIT-D;[394] or
  - relate to an individual's person detriment or property rights.[395]
- Within 30 days of the publication of the final project assessment report, the party disputing a conclusion made in that final report must:
  - give notice of the dispute in writing setting out the grounds for the dispute (dispute notice) to the AER;[396] and
  - at the same time, give a copy of the dispute notice to the RIT-D proponent.[397]
- Within 40 days of receipt of the dispute notice (or within an additional period of up to 60 days where the AER notifies a relevant party that the additional time is required to make a determination because of the complexity or difficulty of the issues involved), the AER must either:
  - reject a dispute (by written notice to the person who initiated the dispute) if the AER considers the grounds are invalid, misconceived or lacking in substance;[398] and
  - notify the RIT-D proponent that the dispute has been rejected;[399] or

391 As defined in draft clause 5.15.1.

392 Draft clause 5.17.5(a)(1).

393 Draft clause 5.17.5(a)(2).

394 Draft clause 5.17.5(b)(1).

395 Draft clause 5.17.5(b)(2).

396 Draft clause 5.17.5(c)(1).

397 Draft clause 5.17.5(c)(2).

398 Draft clause 5.17.5(d)(1).

399 Draft clause 5.17.5(d)(2).

- make and publish a determination either:[400]
  - directing the RIT-D proponent to amend the matters set out in the final project assessment report; or
  - stating that, based on the grounds of the dispute, the RIT-D proponent will not be required to amend the final project assessment report.

- A RIT-D proponent must comply with the AER determination within the timeframe specified by the AER.[401]
- In making a determination, the AER:
  - must only take into account information and analysis the RIT-D proponent could reasonably be expected to have considered or undertaken at the time it performed the RIT-D;[402]
  - must publish its reasons for making a determination;[403]
  - may disregard any matter raised by the disputing party or the RIT-D proponent that is misconceived or lacking in substance;[404] and
  - where making a determination, must specify a reasonable timeframe for the RIT-D proponent to comply with the AER's direction to amend the matters set out in the final project assessment report.[405]
- The AER may only make a determination if it determines that:
  - the RIT-D proponent has not correctly applied the RIT-D in accordance with the rules;[406] or
  - there was a manifest error in calculation performed by the RIT-D proponent in applying the RIT-D.[407]
- The AER may request additional information regarding the dispute from the disputing party or the RIT-D proponent in which case the period of time for rejecting a dispute under paragraph (d)(1) or issuing a determination under paragraph (d)(3) is automatically extended by the

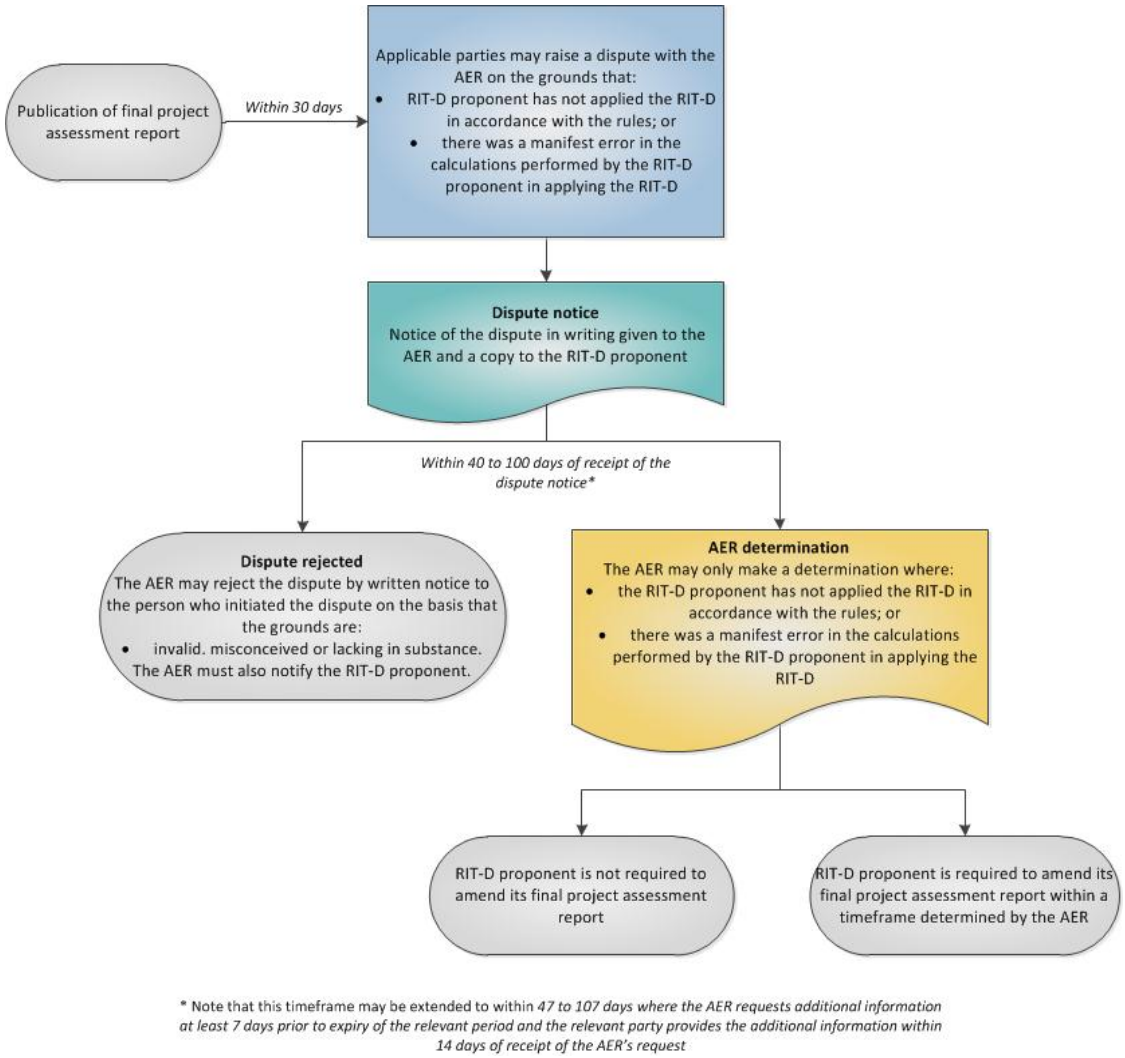
400 Draft clause 5.17.5(d)(3).
401 Draft clause 5.17.5(e).
402 Draft clause 5.17.5(f)(1).
403 Draft clause 5.17.5(f)(2).
404 Draft clause 5.17.5(f)(3).
405 Draft clause 5.17.5(f)(4).
406 Draft clause 5.17.5(g)(1).
407 Draft clause 5.17.5(g)(2).

time it takes the relevant party to provide the additional information to the AER provided:[408]

  - the AER makes the request at least seven days prior to the expiry of the relevant period;[409] and
  - the RIT-D proponent or the disputing party provides the additional information within 14 days of receipt of the request.[410]

- A disputing party or the RIT-D proponent must as soon as practicable provide any additional information requested above to the AER.[411]

Figure 10.1 Dispute resolution process



* Note that this timeframe may be extended to within *47 to 107 days where the AER requests additional information at least 7 days prior to expiry of the relevant period and the relevant party provides the additional information within 14 days of receipt of the AER's request*

408 Draft clause 5.17.5(h).

409 Draft clause 5.17.5(h)(1).

410 Draft clause 5.17.5(h)(2).

411 Draft clause 5.17.5(i).

10.3 Commission's assessment

The Commission has analysed and assessed the policy and drafting issues arising from the rule change request in respect of the proposed dispute resolution process. Outlined below is the Commission's assessment of this matter, including the reasons why it considers this aspect of the draft rule better meets the NEO than the proposed rule.

10.3.1 Dispute resolution process

Scope and process

The dispute resolution process is an important tool in providing a check on the discretion afforded to NSPs during the RIT-D project assessment process. It does so by providing a transparent and accessible mechanism for parties to raise questions regarding a RIT-D proponent's application of the RIT-D, thereby providing accountability for their behaviour.

The dispute resolution process set out in the draft rule is a compliance only test and is limited to an NSP's application of the RIT-D in accordance with the rules. The Commission considers this is an appropriate means of balancing the need for a timely mechanism for parties to question an NSP's decision making process, and the need to ensure that network planning and investment activities are not unduly delayed.

In addition, the Commission supports the dispute resolution process being limited to a DNSP's compliance with the rules rather than a merits review of NSP's decisions. This will ensure that NSPs remain the ultimate decision makers regarding which investments are made. If the review is not limited to compliance against the NER, then the AER would be required to make a decision on the efficiency of an investment and, in effect, apply the RIT-D itself. The Commission does not consider it appropriate for the regulator to take over the role of network planner once a dispute has been raised.

The draft rule expands the scope of parties who may raise a dispute with the AER to include the AEMC, AEMO, connection applicants, intending participants, non-network providers, interested parties (as defined in the rules) and registered participants. The Commission considers it is appropriate for the rules to allow for any party who may be impacted by an NSP's decisions under the RIT-D, including non-network providers and interested parties, to raise a dispute with the AER concerning the process.

A number of stakeholders expressed concern that the proposed scope of the dispute resolution process was too broad and did not provide appropriate safeguards against baseless or vexatious claims being lodged with the effect of delaying projects. To reduce this risk, a number of stakeholders suggested limiting the scope of parties eligible to raise a dispute to those who had participated in the RIT-D consultation process. Alternatively, a number of stakeholders suggested further limiting the scope of matters open to dispute, by not allowing disputes in relation to issues which could have been raised during consultation on a draft project assessment report.

While the Commission acknowledges these concerns, it nonetheless considers that the draft rule provides sufficient safeguards to protect against the risk that the dispute resolution process may be used inappropriately by some stakeholders in certain circumstances. Importantly, the draft rule provides the AER with the ability to reject disputes immediately, if the grounds for dispute are invalid, misconceived or lacking in substance.

In addition, the draft rule sets out a clearly defined process in relation to raising and considering disputes, including a limit on the timing for stakeholders to raise a dispute[412], and on the AER in relation to considering a dispute and determining the outcome[413]. The Commission considers that providing transparency and clarity around these timeframes should provide NSPs with greater certainty regarding the impact of a potential disputes on the timing of an investment, thereby assisting NSPs to better manage any risk associated with the dispute resolution process.

While stakeholders would be encouraged to raise any concerns regarding a RIT-D proponent's application of the RIT-D directly with the DNSP in the first instance (including through the RIT-D consultation process), the Commission considers that it would be inappropriate to expect compliance matters to be resolved informally between these parties. The AER is the body responsible for monitoring compliance with, and investigating possible breaches of, the rules. It is therefore appropriate that any stakeholder who may be impacted by an NSP's decisions under the RIT-D be provided with the opportunity to raise a compliance issue directly with the AER, without being limited in the circumstances in which it may do so.

To be clear, it is not the purpose of the dispute resolution process to provide an avenue for stakeholders to raise disputes simply because they disagree with the conclusions reached by an NSP in its final project assessment report. Rather, the dispute resolution process is intended to provide stakeholders with an opportunity to identify to the AER instances where a RIT-D proponent may not have applied the RIT-D in accordance with the rules, potentially resulting in the RIT-D proponent failing to identify the most efficient option in its final project assessment report. In this instance, it would be necessary for the effectiveness of the process to require the relevant NSP to amend the matters set out in the final project assessment report based on the correct application of the RIT-D rules.

Definition of 'interested party'

In its submission to the consultation paper, the AER noted concern that the current definition of 'interested party' was ambiguous.[414] The proposed rule defines 'interested party' for the purpose of the RIT-T and RIT-D as:

412 Within 30 business days following the publication of a final project assessment report.

413 Within 40-100 days of the receipt of a dispute notice.

414 AER, Consultation Paper submission, p. 9.

> "a person including an end user or its *representative* who, in the AER's opinion, has, or identifies itself to the AER as having the potential to suffer a material and adverse market impact from the proposed *transmission investment* or *distribution investment* (as the case may be) that is the *preferred option* identified in the *project assessment conclusions report* or the *final project assessment report* (as the case may be)."

The AER considered that two aspects of this definition were unclear. First, the AER considered that reference to a person that "*identifies itself as having"* the potential to suffer an impact does not make clear whether:

- by merely identifying themselves, a person is an interested party for the purposes of this definition; or
- the question of whether a person is an interested party for the purposes of this definition is solely a matter for the AER's opinion.

Second, on the basis that 'market' is not italicised in the definition, the AER considered it was unclear whether the material and adverse market impact experienced by the interested party must arise in the national electricity market or in the market for some other good or service.

Having considered the AER's concerns, the Commission has determined that without further clarification, the definition of 'interested party' may unintentionally expand the scope of parties eligible to raise a dispute. On this basis, the draft rule has been clarified such that:

- whether or not a person is an interested party for the purposes of this definition is solely a matter for the AER (in its opinion); and
- the material and adverse market impact experienced by the interested party must arise in the national electricity market.

The Commission considers that this clarification will remove the ambiguity and ensure that only intended parties would be eligible to raise a dispute.

10.3.2 Exemptions from the dispute resolution process

The proposed rule provided for the AER to grant an exemption from the dispute resolution process where it considered the need for a distribution project to proceed would outweigh the benefits from conducting the dispute resolution process.

Having considered the proposal in detail, the Commission is not convinced of its need. Importantly, the Commission does not consider it appropriate to require the AER to determine the need for a particular project to proceed. As noted previously, it is not appropriate for the regulator to take over the role of network planner once a dispute has been lodged.

In addition, the circumstances in which the AER may grant an exemption from the dispute resolution process are adequately dealt with in other provisions in the draft rule. For example, the draft rule provides for the AER, upon receipt of a dispute notice, to dismiss disputes if the grounds for dispute are invalid, misconceived or lacking in substance. In addition, urgent and unforeseen investments (which, arguably, would be the investment type most likely to meet the proposed exemption criteria) are exempt from the RIT-D, and therefore also exempt from the dispute resolution process.

On this basis, the proposal to provide for the AER to grant exemptions from the dispute resolution process is not included in the draft rule.

10.3.3 Determination that a proposed project satisfies a regulatory investment test

The rules in relation to the RIT-T currently provide for a TNSP to request, in writing, that the AER make a determination as to whether a preferred option set out in a RIT-T project assessment conclusions report satisfies the RIT-T.[415] Such a request may only be made after the expiry of the 30 day period in which a relevant party may give notice of a dispute to the AER (and where the preferred option is not for reliability corrective action). The AER must then, within the specified timeframes and having regard to the relevant rules provisions, make and publish a determination on this matter.

While a number of minor amendments have been proposed to this clause to accommodate the proposed joint planning arrangements, the Commission notes that an equivalent provision has not been proposed for inclusion within the new RIT-D rules. The Commission invites stakeholders' views on this matter in submissions to this draft rule determination.

10.4 Rule making test

The Commission is satisfied that the arrangements for the dispute resolution process as set out in the draft rule will, or are likely to, better contribute to the achievement of the NEO relative to the proposed rule. The draft rule is likely to promote efficient investment in distribution networks for the long term interests of consumers of electricity through:

- providing a transparent and accessible mechanism for stakeholders to question NSPs decision making, providing regulatory discipline on NSPs behaviour, thereby promoting efficient decision making;
- building into the process several safeguards to help ensure against distribution projects being unduly delayed, thereby promoting efficient investment in the distribution network; and
- providing clarity for the resolution of disputes by requiring all projects subject to the RIT-D to be within the scope of a common dispute process.

415 NER clause 5.6.6AA(a)-(c).

11 Transition and implementation

This chapter explains the Commission's approach in preparing the draft rule to ensure a smooth transition from existing arrangements to the new national framework for distribution network planning and expansion.

The Commission is mindful that market participants - in particular, DNSPs - should not face unnecessary regulatory risks from a lack of clarity or certainty about the transition to the new national framework. The Commission has therefore sought to manage the transition to the new rules efficiently and with as little disruption as possible. With that said, the Commission invites stakeholders' views on this matter in submissions to this draft rule determination.

It should be noted that any references made in this section to the rule (or certain parts of the rule) commencing is subject to the outcomes of consultation with stakeholders on this draft rule determination and draft rule and, having regard to submissions received from stakeholders during this consultation period, the Commission's final determination on this rule change request.

11.1 Proposed rule

11.1.1 Description of the proposed rule

In the Distribution Network Planning and Expansion Review, the AEMC outlined that its recommendations for the design of a national framework were premised on existing jurisdictional arrangements for distribution network annual planning, annual reporting and project assessment being rolled back to coincide with implementation of the national framework.[416] It was intended that this process be progressed by the states and territories, with the assistance of the Commonwealth where necessary, with ongoing engagement from the AEMC throughout the rule change process.[417]

In the review, the AEMC also indicated that various market participants would need time to transition to a national framework, once the rule commenced.[418] Specifically, the AEMC indicated that:

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416 AEMC 2009, *Review of National Framework for Electricity Distribution Network Planning and Expansion*, Final Report, 23 September 2009, Sydney, p. 9.

417 In its final report for the review, the AEMC indicated that it was appropriate for a 'transition plan' to be developed and agreed by the jurisdictions as part of the MCE's response to the AEMC's final report. In its response to the AEMC's final report, the MCE stated that it supported the AEMC's ongoing engagement with the Commonwealth, states and territories throughout the rule change process, to ensure an efficient transition to the new national framework. See: AEMC 2009, *Review of National Framework for Electricity Distribution Network Planning and Expansion*, Final Report, 23 September 2009, Sydney, p. 9; and MCE 2010, *Review of National Framework for Electricity Distribution Network planning and Expansion: Response to the Australian Energy Market Commission's Final Report*, September 2010.

418 AEMC 2009, *Review of National Framework for Electricity Distribution Network Planning and Expansion*, Final Report, 23 September 2009, Sydney, pp. 8-9.

- DNSPs would require a minimum period of nine months (following the making of the rule) before being required to publish their first DAPR. This would ensure DNSPs were provided with sufficient time to comply with the new planning and reporting requirements;[419] and

- the AER should be provided with a period of 12 months to develop and prepare the RIT-D and RIT-D application guidelines. The proposed rule therefore provided for a one year transition period to apply before the RIT-D commenced, following the making of the rule.[420]

Although these transitional issues were not discussed in detail in the final report from the AEMC's review, the proposed rule provided DNSPs with a period of nine months following commencement of the rule, to prepare and publish their first demand side engagement document.[421]

11.1.2 Stakeholder views

Duplication of state and national arrangements

In submissions to the consultation paper, the ENA and several DNSPs expressed concern regarding the potential for duplication of distribution network planning and expansion requirements at a national and jurisdictional level.[422] Energex was of the view that the transition to a national framework may be difficult to achieve given the considerable time required to amend jurisdictional regulatory instruments. It considered this issue needed to be provided for by transitional provisions in the NER.

The ENA considered that a clear commitment needed to be made to removing jurisdictional requirements to accommodate the introduction of the new national framework. The Victorian DNSPs also suggested that the AEMC work with jurisdictions to agree a timetable for implementation, and to ensure the roll-back of jurisdictional frameworks was coordinated.

Transition to a national framework

Aurora Energy expressed concern that the proposed timeframes for market participants to comply the new requirements of the national framework would not be

419 While the AEMC final report recommended that this transition period apply to DNSPs, the proposed rule did not formally incorporate this time period as a specific provision.

420 This 12 month period is provided for in the proposed amendments to the NER Chapter 11 savings and transitional arrangements.

421 Proposed clause 5.6.2AA(m). Note that the proposed rule did not provide timeframes within which DNSPs would be required to have established their demand side engagement database and register.

422 ENA, Consultation Paper submission, pp. 3, 5; Ergon Energy, Consultation Paper submission, p. 4; Energex, Consultation Paper submission, p. 20; Victorian DNSPs, Consultation Paper submission, pp. 7, 6, 17; Endeavour Energy, Consultation Paper submission, p. 10.

appropriate for all jurisdictions.[423] It suggested that each jurisdiction would be best placed to advise the AEMC on transition planning.

Essential Energy considered the proposed timeframes for compliance with the new requirements would create significant challenges for the NSW DNSPs in particular, given that each business would be in the process of preparing their regulatory proposal for lodgement in May 2013. Essential Energy suggested that a more appropriate commencement date for NSW DNSPs would be mid-2014.[424]

In contrast, the Victorian DNSPs considered the timings provided for DNSPs to transition to the national framework, although challenging, would be achievable.[425] The Victorian DNSPs supported the proposed nine months for preparation of first DAPR and the proposed transitional period of 12 months for the RIT-D. However, they also noted that the rule should include a 12 month transitional period for the RIT-T for joint investments.

Transition from the regulatory test to the RIT-D

A number of DNSPs were concerned that the proposed rule did not provide guidance regarding the stage at which DNSPs would be required to comply with the RIT-D for projects that had commenced under the regulatory test.[426] These stakeholders suggested that any project assessment not complete at the date of the relevant amendment to the RIT-D and/or the RIT-D application guidelines should continue and be completed under the regulatory test.

In their supplementary submissions, two of these stakeholders further suggested that the draft rules provide for DNSPs to identify to the AER (at the time of the final determination) the proposed projects which had commenced data analysis under the regulatory test, and which DNSPs intend to complete their assessment under the regulatory test.[427] These projects would then be exempt from the requirements of the RIT-D project assessment process.

In addition, several stakeholders were concerned that the proposed rule did not acknowledge that compliance with the RIT-D would only commence after publication of the RIT-D rules and associated application guidelines. These stakeholders suggested that the rules should specify the timeframe, after the release of the application guidelines, within which a DNSP would be required to comply.[428] The ENA and

423 Aurora Energy, Consultation Paper submission, p. 10.

424 Essential Energy, Consultation Paper submission, p. 8.

425 Victorian DNSPs, Consultation Paper submission, p. 6.

426 ENA, Consultation Paper submission, p. 22; Energex, Consultation Paper submission, p. 21; Essential Energy, Consultation Paper submission, p. 9; Endeavour Energy, Consultation Paper submission, p. 10.

427 ENA, Consultation Paper supplementary submission, pp. 1-2; Energex, Consultation Paper supplementary submission, p. 4.

428 ENA, Consultation Paper submission, p. 22; Energex, Consultation Paper submission, p. 20; Ergon Energy, Consultation Paper submission, pp. 4, 17; Endeavour Energy, Consultation Paper submission, p. 11.

Energex considered a six month transitional period was necessary.[429] Ergon Energy considered a transitional period of at least 12 months would be required in order to provide DNSPs with sufficient time to understand the new regulatory requirements and to adapt processes, procedures, documentation and information systems, as relevant.[430] Endeavour Energy also noted that DNSPs would require time to train and prepare staff for the commencement of the rule, to ensure compliance.[431]

11.2 Application of the proposed rule and proposed modifications

The Commission proposes to largely adopt the principles behind the proposed rules in relation to implementation of, and transition to, the new national framework as described in section 11.1.1. However, the Commission has made several amendments to the proposed rule, including changes to the proposed timeframes for implementation. The manner and reasoning for these amendments are set out below.

11.2.1 Amendments

Having regard to the views of stakeholders in submissions to the consultation paper, and having undertaken its own analysis and review, the Commission has made several modifications to improve the application of the rule and better promote the NEO. These modifications are as follows:

- *Publication of the first DAPR*: the draft rule includes a transitional provision providing DNSPs with a minimum period of six months after the rule commences before being required to publish their first DAPR.[432]
- *DAPR content*: the draft rule includes a transitional provision clarifying that DNSPs will not be required to report on projects assessed under the RIT-D in their DAPRs until such time as the RIT-D rules commence. DNSPs will however be required to report on projects which have been (or will be) assessed under the regulatory test during that period.[433]
- *Establishment of the demand side engagement register*: the draft rule includes a new provision requiring DNSPs to establish their demand side engagement register by the date of publication of their first demand side engagement document.[434]
- *Publication of the RIT-D and RIT-D application guidelines*: the draft rule requires the AER to develop and publish the RIT-D and RIT-D application guidelines by the date which is nine months from the date the rule commences.[435]

429 ENA, Consultation Paper submission, p. 22; Energex, Consultation Paper submission, p. 20.

430 Ergon Energy, Consultation Paper submission, pp. 4, 17.

431 Endeavour Energy, Consultation Paper submission, p. 11.

432 Draft clause 11.[xx].2.

433 Draft clause 11.[xx].4.

434 Draft clause 5.13.2(j).

- *Transition from the regulatory test to the RIT-D*: the draft rule includes a number of transitional provisions including requiring that:
  - DNSPs submit to the AER, by 31 December 2013, a list of projects which the DNSP has commenced assessing under the regulatory test. Unless otherwise determined by the AER, these projects would be exempt from consideration under the RIT-D project assessment process and would continue to be assessed under the regulatory test;[436] and
  - in the first RIT-D application guidelines, the AER provide guidance as to when a regulatory test assessment will be considered to have 'commenced'.[437]

In line with the proposed rule, the draft rule also provides for the RIT-D to commence 12 months after the date the rule commences (where the Commission determines to make a final rule). The Commission has also identified 1 January 2013 as a possible date for commencement of a final rule. Further discussion on these matters is provided below.

11.2.2 Description of the draft rule

The majority of the amendments set out above are incorporated into the relevant sections of the draft rule. A savings and transitional rule has also been provided to clarify the arrangements in respect of publication by a DNSP of its first DAPR and the arrangements for the transition from the regulatory test to the RIT-D.

Box 11.1 provides a summary of these transitional rules. Figure 11.1 then illustrates the proposed implementation timeframes, based on the arrangements in the draft rule.

Box 11.1: Savings and transitional rules

First DAPR:

- If the first DAPR date for a DNSP is less than six months after the date the rule commences then the DNSP is not required to publish its first DAPR until the second DAPR date for that DNSP after the commencement date.[438]

435 Draft clause 5.17.2(d).

436 Draft clause 11.[xx].3(c).

437 Draft clause 11.[xx].3(d).

438 Draft clause 11.[xx].3.

DAPR:

- If a DAPR is published in the period from the commencement of the rule to the RIT-D commencement date, then the DNSP is not required to include the information specified in new schedule 5.8(e) and (f) in its DAPR and must instead include information specified in the savings and transitional provision in relation to the regulatory test.[439]

Transition from the regulatory test to the RIT-D:

- The RIT-D commencement date is the date that is one year from the date the rule commences.[440]
- By 31 December 2013, each DNSP must submit to the AER a list of projects which the DNSP has commenced assessing under the regulatory test.[441]
- In the first RIT-D application guidelines, the AER must provide guidance as to when a regulatory test assessment will be considered to have commenced.[442]
- The AER must, having regard to any guidelines made, determine that a project or projects in the list submitted by a DNSP have not commenced assessment under the regulatory test.[443]
- From 31 December 2013, RIT-D projects must be assessed under the RIT-D unless they have commenced assessment under the regulatory test.[444]

439 Draft clause 11.[xx].4.

440 Draft clause 11.[xx].2.

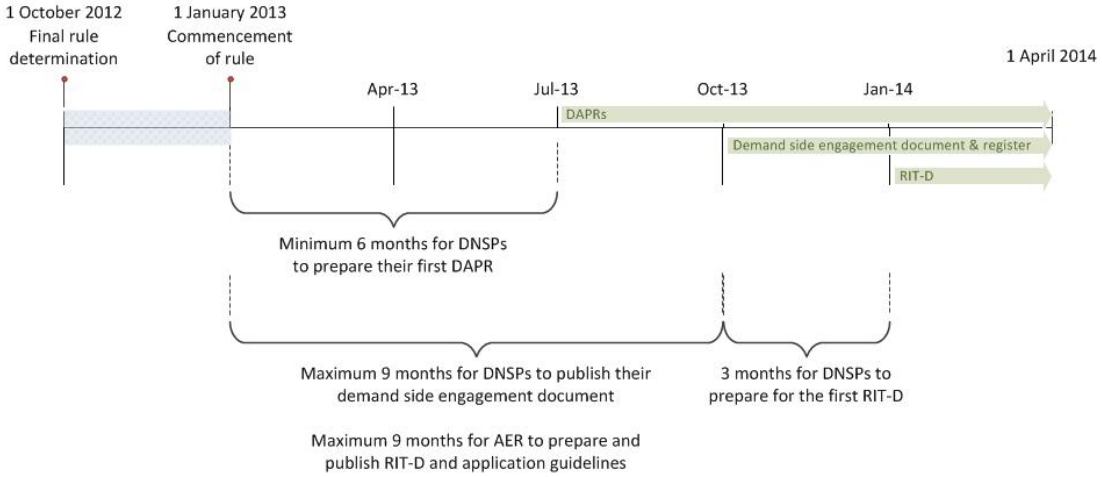
441 Draft clause 11.[xx].5.(c).

442 Draft clause 11.[xx].5.(d).

443 Draft clause 11.[xx].5(e).

444 Draft clause 11.[xx].5 (b).

Figure 11.1 Implementation and transition timeframes



11.3 Commission's assessment

11.3.1 Roll-back of jurisdictional arrangements

As noted previously, implementation of this rule change is based on the assumption that the existing jurisdictional arrangements for annual planning, annual reporting and project assessment (to the extent that they are covered by the new national framework) will be rolled back to coincided with the introduction of the national framework.

The Commission understands that all jurisdictions have commenced (to varying degrees) the process of reviewing and rolling back duplicate local planning arrangements.[445] The AEMC will continue to keep the jurisdictions informed on the progress of the rule change assessment, and the details of the rule to be implemented, to assist them in this process.

11.3.2 Potential date for commencement of a final rule

The Commission has identified 1 January 2013 as a possible commencement date for a final rule (where the Commission determines to make a final rule). Based on the information made available from jurisdictions, this date would allow the majority of DNSPs to prepare their annual planning reports for 2012 under existing arrangements, while providing a minimum period of six month for DNSPs to prepare their annual planning reports for 2013 under the new arrangements.[446]

445 The draft rules provide flexibility for jurisdictions to retain any specific jurisdictional requirements where these are not covered by the requirements of the national framework.

446 This is based on the assumption that each jurisdiction will retain the current dates set out in jurisdictional legislation as the 'DAPR date' (with the exception of NSW, which does not currently prescribe in legislation a date for publication of the network management plans).

It is anticipated that a 1 January 2013 commencement date would allow sufficient time for the jurisdictions to make the necessary amendments to relevant state based instruments to ensure that there is no duplication with the national framework.

11.3.3 Transition to the national framework

Publication of the DAPR

As noted previously, it was intended that DNSPs be provided with a minimum period of nine months before being required to publish their first DAPR. This period of time (beginning from the date the rule commenced) was considered sufficient to enable DNSPs to comply with the new planning and reporting requirements.

While the Commission understands the importance of providing DNSPs with sufficient time to undertake the necessary preparatory work to ensure compliance with the new reporting requirements, it also notes the importance of ensuring that the benefits of DNSPs reporting under the new national framework can be achieved in a timely manner.

Assuming a commencement date of 1 January 2013 for the final rule, providing DNSPs with a minimum period of nine months to prepare their first DAPR would result in a number of DNSPs not publishing a DAPR until 2014 – a considerable period of time after the start of the rule.[447]

The draft rule therefore provides DNSPs with a minimum period of six months from the proposed commencement date of the rule before publication of the first DAPR. This will ensure that the majority of DNSPs will publish an annual planning report for 2013 under the new national framework.

In addition, on the basis that the final determination for this rule change request will be published prior to December 2012, the Commission notes that DNSPs will have additional time from the publication of the final determination to prepare for compliance with the new arrangements come 1 January 2013.

Publication of the demand side engagement document

The proposed rule provided DNSPs with a maximum period of nine months to publish their first demand side engagement document. The Commission considers nine months is sufficient time for DNSPs to prepare the information required for publication in this document.

The proposed rule did not specify a timeframe within which DNSPs would be required to have established their demand side engagement registers. The Commission considers it is appropriate to require that the register be established by the date a DNSP publishes its demand side engagement document. The draft rule reflects this intent.

447 For example, those DNSPs whose DAPR date is specified in the period from January to September.

Publication of the RIT-D and RIT-D application guidelines

The proposed rule did not specify a date by which the AER was required to publish the RIT-D and RIT-D application guidelines. However, given that the proposed rule provided for a one year transition period to apply before commencement of the RIT-D, it was expected that the AER would develop and publish the RIT-D and RIT-D application guidelines by the date 12 months following commencement of the rule.[448]

The Commission notes that it is important to ensure that sufficient time is made available for the AER to undertake all stages of its process to develop the RIT-D and RIT-D application guidelines (including providing stakeholders with adequate time to respond to key issues). However, this must be balanced with the need to ensure that this initial step in the broader regulatory framework is undertaken in an efficient and timely manner. Given the AER has considerable experience in the current regulatory test and the RIT-T, the Commission considers that providing the AER with a period of nine months to prepare and publish the RIT-D and application guidelines will achieve an appropriate balance between these objectives. The draft rule therefore requires the AER to publish the test and guidelines nine months from commencement of the rule.

In addition, the Commission notes that the delay between publication of the final determination (expected prior to December 2012) and the proposed commencement date of the rule (1 January 2013) provides a period of at least several months within which the AER may wish to prepare for commencement of the rule in January 2013.

Commencement of the RIT-D

As noted previously, the proposed rule provided for a one year transition period to apply before commencement of the RIT-D. During this period, the AER would be expected to develop and publish the RIT-D and RIT-D application guidelines.

In submissions to the consultation paper, a number of stakeholders expressed concern that the proposed rule did not specify a date following the release by the AER of the RIT-D and RIT-D application guidelines, by which DNSPs would be expected to comply with the new RIT-D rules. Stakeholders suggested that six months[449] or a period of at least 12 months[450] would be required.

Having considered this issue in detail, the Commission has determined that the rule should provide DNSPs with a period of three months following publication of the RIT-D and RIT-D application guidelines, in order to finalise preparations for compliance with the new RIT-D project assessment and consultation process.

The Commission considers three months is appropriate given that DNSPs would be expected to have commenced preparations for transition to the new RIT-D prior to the AER finalising the test and application guidelines. At the very least, publication of the draft RIT-D and RIT-D application guidelines should provide DNSPs with a level of

448 Proposed clause 11.30.

449 ENA, Consultation Paper submission, p. 22; Energex, Consultation Paper submission, p. 21.

450 Ergon Energy, Consultation Paper submission, p. 10.

information sufficient to understand the new regulatory requirements and begin the process of adapting processes and procedures to ensure compliance.[451]

11.3.4 Transition from the regulatory test to the RIT-D

In submissions to the consultation paper, a number of DNSPs were concerned that the proposed rule did not provide guidance regarding the stage at which DNSPs would be required to comply with the RIT-D for projects that had commenced assessment under the regulatory test. Two stakeholders suggested that the draft rules provide for identification to the AER (at the time of the final determination) of proposed projects which had commenced data analysis under the regulatory test.[452] These projects would then be exempt from assessment under the RIT-D project assessment process.

The Commission notes that it is not the intention for a RIT-D project which has commenced (or recently completed) an assessment under the regulatory test, to have to undergo further assessment under the RIT-D project assessment process once the RIT-D rules commence.[453]

In order to provide clarity on this issue, the draft rule requires DNSPs to submit to the AER, by 31 December 2013, a list of RIT-D projects which have commenced assessment under the regulatory test. Unless otherwise determined by the AER, these projects would then be exempt from consideration under the RIT-D (but would continue assessment under the regulatory test). The Commission considers that this approach will provide an effective and efficient means of ensuring a smooth transition to the new project assessment process.

The draft rule does not include a formal process around the approval by the AER of a DNSPs list of RIT-D projects considered to have commenced assessment under the regulatory test. However, it is expected that there will be some interaction between the AER and DNSPs in finalising and approving the lists.

To provide some guidance to DNSPs in relation to when the AER considers that a regulatory test assessment will have commenced, the draft rule also requires the AER to provide guidance on the meaning of this term in its RIT-D application guidelines.[454]

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451 No change has been made to the proposed rule which requires the RIT-D to commence 12 months after the date the rule commences. Rather, the three month transition period will arise as an outcome of the amended timeframe provided to the AER to develop and publish the RIT-D and application guidelines.

452 ENA, Consultation Paper supplementary submission, pp. 1-2; Energex, Consultation Paper supplementary submission, p. 4.

453 An exception to this would be where a material change in circumstance has occurred in accordance with draft clauses 5.17.4(t) and (u).

454 Requiring the AER to provide guidance in the RIT-D application guidelines would also minimise the risk that DNSPs' interpretations of the term 'commenced assessment' may be influenced by a desire to subject as many projects as possible to the requirements of the regulatory test rather than to the requirements of the new RIT-D project assessment process.

Transition from the regulatory test to the RIT-D for joint planning projects

It is intended that NSPs would comply with the joint planning provisions set out under draft clause 5.14 from the date of commencement of the final rule (where the Commission determines to make a final rule). However, until such time as the RIT-D rules commence, a transitional rule may be needed to clarify that:

- in respect of RIT-T projects identified through the joint planning process, in all cases a TNSP must be identified as the lead party and must carry out the requirements of the RIT-T; and

- in respect of RIT-D projects identified through the joint planning process, in all cases a DNSP must be identified as the lead party and must carry out the requirements of the regulatory test.

For the avoidance of doubt, DNSPs would also be required to include on their list of RIT-D projects to be provided to the AER by 31 December 2013, any RIT-D projects which are joint planning projects and which have commenced assessment under the regulatory test. These joint planning projects would also be exempt from consideration under the RIT-D (but would continue assessment under the regulatory test).

11.4 Rule making test

The Commission is satisfied that the implementation and transitional rules as set out in the draft rule will, or are likely to, contribute to the achievement of the NEO. The draft rules on this matter of implementation will help to ensure a smooth transition to the new distribution planning and expansion framework without creating unnecessary regulatory burden for market participants affected by the rule.

Abbreviations

ACG	Allen Consulting Group
AEMA	Australian Energy Market Agreement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CDC	Copper Development Centre
CEO	Chief Executive Officer
COAG	Council of Australian Governments
Commission	See AEMC
CPRS	Carbon Pollution Reduction Scheme
DAPR	Distribution Annual Planning Report
DNSP	Distribution Network Service Provider
DSP	Demand Side Participation
DUOS charges	Distribution Use of System charges
ENA	Energy Networks Association
EURCC	Energy Users Rule Change Committee
MCE	Ministerial Council on Energy
MCE SCO	MCE Standing Committee of Officials
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules

NERA	NERA Economic Consulting
NSP	Network Service Provider
proponent	See MCE
RET	Renewable Energy Target
RIT-D	Regulatory investment test for distribution
RIT-T	Regulatory investment test for transmission
rules	See NER
STT	Specification threshold test
TAPR	Transmission Annual Planning Report
TFR	Transmission Frameworks Review
the review	Review of National Framework for Electricity Distribution Network Planning and Expansion
TNSP	Transmission Network Service Provider

A Summary of policy issues raised in submissions

The table below provides a summary of the policy issues raised by stakeholders in their submissions and supplementary submissions to the consultation paper.[455] The table, ordered by component of the national framework, sets out the Commission's response to each issue.

For ease of reference, relevant page numbers have been included in the table.

The submissions and supplementary submissions received are available on the AEMC website at www.aemc.gov.au.

Stakeholder	Issue	AEMC Response
Annual Planning Review		
Forward planning period		
ENA (p. 5), Ergon Energy (p. 4), Energex (p. 1), Victorian DNSPs[456] (p. 2), Aurora Energy (p. 2), Ausgrid (p. 3), Endeavour Energy (p. 1), ETSA Utilities (p. 4), Essential Energy (p. 4), Origin (p. 1)	These stakeholders were supportive of the proposal to allow each jurisdiction to determine the start date for the forward planning period. The ENA and the Victorian DNSPs did not consider that aligning planning periods nationally would facilitate transparency. Rather, they considered it would reduce the usefulness and relevancy of the published information.	Noted. Consistent with the proposed rule, the draft rule requires that a DNSP's forward planning period commence one day after the 'DAPR date' (previously the 'jurisdiction specified date'). The 'DAPR date' is the date specified under jurisdictional electricity legislation by which a DNSP must publish its DAPR. Where no such date is specified, the draft rule requires a DNSP to publish its DAPR by 31 December for the forward planning period commencing 1 January.
AER (p. 2), EnerNOC (p. 3)	The AER and EnerNOC were supportive of the inclusion of a uniform start date for the annual planning period and publication of the DAPRs.	Noted. See section 5.3.1 for further discussion on this matter.

455 Appendix B provides a summary of the legal issues raised by stakeholders in their submissions and supplementary submissions to the consultation paper.

456 The Victorian distribution businesses are CitiPower and Powercor Australia, United Energy, SP AusNet and Jemena Electricity Networks.

Stakeholder	Issue	AEMC Response
	The AER considered this would improve transparency and consistency in industry practices and more effectively facilitate joint planning across jurisdictions and between transmission and distribution networks. EnerNOC considered a single start date would be beneficial given the possibility of projects that cover more than one jurisdiction.	
Default date		
Ergon Energy (p. 7), Victorian DNSPs (p. 14), Endeavour Energy (p. 1), Essential Energy (p. 4)	These DNSPs considered it would not be necessary to include a default start date for the forward planning period in the rules. Further, Ergon Energy considered this date should be subject to jurisdictional transitional arrangements to ensure DNSPs would not be unfairly subject to complying with both jurisdictional and new national reporting requirements.	As noted above, where a DAPR date has not been specified, the draft rule requires a DNSP to publish its DAPR by 31 December for the forward planning period beginning 1 January. The Commission considers it is appropriate to specify a default date in the rules. This will help to avoid confusion in the instance a jurisdiction has not specified a DAPR date and to ensure DNSPs are clear in respect of their planning and reporting obligations.
AER (p. 2), Aurora Energy (p. 2), EnerNOC (p. 3)	These stakeholders supported the inclusion in the rules of a default start date for the forward planning period.	Noted. As above.
Distribution Annual Planning Report		
Exemptions or variations to the annual reporting requirements		
ENA (p. 8), Ergon Energy (p. 8), Energex (p. 3), Victorian DNSPs (p. 9), Endeavour Energy (pp. 4, 11), Essential Energy (p. 5),	These stakeholders were supportive of the proposal to allow exemptions or variations to the proposed annual reporting requirements. Ergon Energy considered, at the very least, exemptions	Noted. The draft rule does not enable the AER to grant exemptions or variations to the annual reporting requirements set out in draft schedule 5.8. The Commission's preference is to focus on the detailed

Stakeholder	Issue	AEMC Response
EnerNOC (p. 4), Ausgrid (p. 4)	should apply when requested during transitional periods. Similarly, Endeavour Energy considered the ability to seek an exemption would be more efficient in situations where the application of jurisdictional requirements and the national framework lead to a duplication of processes. Essential Energy considered the proposal would provide a mechanism to balance a DNSP's circumstances and jurisdictional requirements, and would provide DNSPs with time to develop systems to comply with the national framework at a later date. Ausgrid considered the rules should be flexible to be reflective of current planning processes unless there was a clear reason that current processes were inadequate.	requirements of schedule 5.8 to ensure these are appropriate and fit for purpose for each DNSP. Where a specific requirement is unlikely to prove workable for a particular DNSP, it may be necessary to consider providing some flexibility within the rules, where appropriate. The Commission would be interested in feedback from stakeholders on whether any of the reporting requirements set out in draft schedule 5.8 are likely to be particularly problematic, and the reasons why. See section 6.3.1 for further discussion on this matter.
AER (p. 3), Origin (p. 1), AEMO (p. 1), Aurora Energy (p. 4)	These stakeholders did not support the proposal to allow exemptions or variations to the proposed annual reporting requirements. The AER considered the information proposed for inclusion in the DAPR was core network planning information which, for the most part, should be considered by DNSPs in undertaking their current planning activities. On this basis, the AER considered the disclosure of this information should not provide unwarranted additional cost or regulatory burden. Aurora Energy considered that there should be no reason for exemptions from, or variations to, the annual reporting requirements unless the information is not available.	Noted. As above.
Endeavour Energy (p. 4)	Endeavour Energy suggested that a more general	Noted. In line with the Commission's views above, where it

Stakeholder	Issue	AEMC Response
	exemption clause may be appropriate to capture instances where the need for an exemption/variation does not directly relate to economic cost arguments. For example, forecasts of generation capacity could be subject to commercial in confidence arrangements with individual generators.	is considered that a specific reporting requirement may prove problematic, including from a risk point of view, the Commission would encourage stakeholders to identify the relevant requirement in submissions to the draft rule determination. This will enable the Commission to consider the matter further ahead of making its final determination.
ENA (p. 8)	The ENA considered any minimum set of core reporting requirements should extend only to common information already published by DNSPs in their current annual planning reports.	Noted. No longer relevant due to drafting changes.
AER (p. 3)	The AER did not support an alternate approach of allowing exemptions or variations for only some of the proposed information. The AER considered all the information to be included in the DAPR was important for a variety of purposes and was necessary to provide a comprehensive overview of DNSPs' approaches to forward planning.	Noted. As above.
ENA (p. 8), Victorian DNSPs (p. 14)	The ENA and the Victorian DNSPs did not support use of the term 'manifestly' in proposed clause 5.6.2AA(v) on the basis that it is subjective and difficult to demonstrate.	Noted. As above
Aurora Energy (p. 5)	Aurora Energy considered that proposed clause 5.6.2AA(v) contained perverse incentives for DNSPs to inflate the estimated costs of reporting and for the AER to overestimate the benefits of reporting.	Noted. As above.
Victorian DNSPs (p. 15)	The Victorian DNSPs noted that, while the cost of preparing information for inclusion in the DAPR could be reasonably estimated, estimates of the potential benefits would be more subjective and best dealt with on a case by case basis.	Noted. As above.

Stakeholder	Issue	AEMC Response
ENA (p. 8), Ergon Energy (p. 8), Endeavour Energy (p. 4)	These stakeholders supported the inclusion of a set of criteria to assist DNSPs in developing, and the AER in assessing, applications for exemptions from, or variations to, the proposed annual reporting requirements. Endeavour Energy considered that workable criteria would allow DNSPs to apply for exemptions or variations to specific items.	Noted. As above.
Energex (p. 3), Essential Energy (p. 5)	Neither Energex nor Essential Energy supported the inclusion of a set of criteria to assist DNSPs in developing, and the AER in assessing, applications for exemptions or variations to the proposed annual reporting requirements. Energex was opposed on the basis that there was no national consistency amongst DNSPs in their approach to the preparation and analysis of data. Essential Energy suggested that a guideline or application template would be more appropriate in assisting DNSPs in demonstrating excessive costs.	Noted. As above.
ENA (p. 8), Victorian DNSPs (p. 15), Ergon Energy (p. 8)	In respect of the process for applying for an exemption or variation, the ENA and the Victorian DNSPs considered that the AER should be required to: (1) make and publish a draft determination on an application within a specified period; (2) provide a reasonable period for interested parties to lodge submissions on the draft decisions; and (3) make and publish a final determination within a specified period. Ergon Energy also suggested that the AER be required to provide reasons for its determination.	Noted. As above.

Stakeholder	Issue	AEMC Response
Certification of the DAPR		
ENA (p. 9), Victorian DNSPs (p. 3), Essential Energy (pp. 5-6)	These stakeholders did not support the proposed DAPR certification requirements. The ENA and the Victorian DNSPs considered certification by the CEO and a Director or Company Secretary was inappropriately onerous. They suggested that certification by the COO or relevant general manager would be appropriate. Given the scope of the information reported in the DAPR, Essential Energy considered sign off by an executive manager would be more appropriate.	The draft rule does not require that DNSPs' DAPRs be certified by the CEO and a Director or Company Secretary of each DNSP. The Commission considers that there are already a number of regulatory mechanisms and incentives which will help to ensure that DNSPs deliver robust, high quality DAPRs, in line with the draft rule. See section 6.3.2 for further discussion on this matter.
Public forum on the DAPR		
Victorian DNSPs (p. 4)	The Victorian DNSPs considered that the requirement for DNSPs to hold a public forum called on request by any member of the public may be open to vexatious claims. In addition, they considered that a public forum was not an effective or informative method for communicating highly technical details which require careful consideration of the details and facts set out in the reports.	The draft rule does not require DNSPs to conduct a public forum on their DAPRs if requested to do so by a relevant party. The Commission agrees with the view that a public forum may not be the most effective way of communicating to third parties the type of information to be included in the DAPRs. However, to ensure the lines of communication on these matters are open, the draft rule includes a new obligation on DNSPs to provide the contact details for a suitably qualified staff member of the DNSP to whom enquiries on the contents of the DAPR may be directed. The relevant contact details are to be included on the DNSPs website. See section 6.3.2 for further discussion on this matter.

Stakeholder	Issue	AEMC Response
Energex (p. 4)	Energex was concerned that the proposed rule did not provide a deadline by which a party must request a public forum, but simply a deadline by which the public forum must be held. Energex suggested amendments to this requirement.	Noted. As above.
DAPR reporting requirements		
ENA (p. 9), Ausgrid (p. 4), Aurora Energy (p. 4)	These stakeholders questioned whether all the information proposed to be published in the DAPRs was required for planning purposes. The ENA noted that some of the information contained within proposed schedule 5.8 resembled information requested by the AER in assessing a DNSP's forecast capital expenditure. In addition, it noted that some of the information was similar to the information that the AER had proposed to obtain from DNSPs in an annual regulatory information order for performance reporting purposes. The ENA considered it was inappropriate to include information already requested and/or available via other regulatory mechanisms, in the DAPR. This view was supported by Ausgrid.	Requiring DNSPs to publish their DAPRs on their website will ensure that the information they contain is readily available to any interested stakeholder, including the AER and other regulatory bodies. On this basis, the Commission notes that the draft rule may reduce the need for similar information to be obtained from DNSPs via other regulatory mechanisms. In addition, the Commission notes that the scope of the reporting requirements, although broader than information on system limitations, is intended to provide important context to DNSPs planning activities. It is intended that this supporting information be provided at a higher level than the more detailed information on system limitations. On this basis, the Commission does not consider that preparation and publication of the DAPR should result in significant additional cost to each DNSP.
Energex (p. 3)	Energex suggested that further clarification be provided in regards to the phrase 'voltage regulation' in proposed clause 5.6.2AA(g)(2). Specifically, what is required to be published in the DAPR.	Voltage regulation refers to variations in voltage with changing load conditions. Draft clause 5.13.2(d)(2) confirms that a limitation caused by a requirement for voltage regulation would constitute a 'system limitation' for the purposes of this rule. DNSPs would therefore be required to report on any system limitations which may have been caused by a requirement for voltage regulation in accordance with draft schedule 5.8(4).

Stakeholder	Issue	AEMC Response
Energex (p. 4)	Energex noted that it has numerous policies impacting asset management. As such, Energex expressed concern that in demonstrating that the planning review had been undertaken in line with these policies, a DAPR would contain an excessive volume of information, thereby reducing its value. On this basis, it requested further clarification as to the type of policies referred to in proposed clause 5.6.2AA(g)(4).	The draft rule does not require DNSPs to undertake the annual planning review in a manner which is consistent with its asset management policies. To the extent that such compliance is required by jurisdictional instruments, this will be captured by draft clause 5.13.2(d)(4). With that said, the Commission recognises that asset management forms an important overall component of the planning process. The Commission would therefore expect DNSPs to undertake effective asset management in carrying out all aspects of their planning activities.
Energex (p. 4)	Energex considered that it was unclear how 'forecasts' of reliability targets could be provided under proposed clause S5.8(2)(iv).	The draft rule clarifies that DNSPs are required to report on their forecasted performance against the reliability targets set out in the service target performance incentive scheme developed by the AER under NER clause 6.6.2.
Energex (p. 5)	Energex noted that it was unclear why the estimates referred to in various clauses throughout proposed clause S5.8 should be 'best' estimates.	The inclusion of the term 'best estimate' was intended to recognise that forecasts of system limitations are subject to a number of variables which may make it difficult for some DNSPs to forecast the exact month in which a system limitation would occur. However, the Commission is satisfied that this objective would also be achieved by reference to the term 'estimate'. The draft rule therefore incorporates this drafting.
Victorian DNSPs (p. 4)	The Victorian DNSPs did not agree that providing load forecasts for the network as a whole was necessary on the basis that such forecasts would not aid the decision of how to relieve constraints.	The Commission agrees that the provision of load forecasts for the network as a whole would be unlikely to assist in the consideration of system limitations. The draft rule therefore does not require DNSPs to prepare and report on load forecasts at the network level. However, the Commission notes that DNSPs would not be prevented from preparing and reporting this information

Stakeholder	Issue	AEMC Response
		where they consider it appropriate.
Ausgrid (p. 4), Essential Energy (pp. 5-6)	Ausgrid considered that providing annual forecasts for each primary feeder would not add benefit and would only add cost. Essential Energy also suggested further consideration be given to the definition of a “primary feeder” as the present definition would result in significant reporting demand for a large number of distribution feeders, with little benefit. Essential Energy suggested that relating the “primary feeder” definition reporting requirements to the NSW jurisdiction “–1” distribution feeder security reporting could be an appropriate option.	Due to the number of primary distribution feeders and the nature of preparing forecasts for these assets, the draft rule only requires information to be provided on primary distribution feeders which are overloaded (or forecast to be overloaded within the next two years) where these have been identified by the DNSP. The definition of primary distribution feeder is based on the functionality of the assets rather than specific voltage levels. The Commission considers this approach to the definition is appropriate and will capture all the required assets.
Endeavour Energy (p. 4)	Endeavour Energy considered the requirements of proposed clause S5.8 were overly prescriptive.	Noted. The Commission considers that the information to be included in the DAPR is important and necessary to provide transparency to DNSPs planning activities.
Essential Energy (pp. 5-6)	Essential Energy considered the month and year requirement for timing of identified constraints was unrealistic on the basis that maximum demands can vary. Essential Energy suggested that a season of year would be more realistic.	As noted above, the inclusion of the term 'best estimate' was intended to recognise that forecasts of system limitations are subject to a number of variables which may make it difficult for some DNSPs to forecast the exact month in which a system limitation would occur. While the draft rule removes reference to the term 'best', DNSPs are nonetheless only required to provide an estimate (rather than the exact month and year) of when a system limitation would be expected to occur.
Essential Energy (pp. 5-6)	Essential Energy considered there was an imbalance between the reasonably detailed requirements set out in proposed schedule 5.8 for 'loads' as a driver for network investment and the other drivers included in proposed schedule 5.8(2)(v)(a)(b)(c)(d) (that is: fault levels, voltage	Noted.

Stakeholder	Issue	AEMC Response
	levels, other power system security requirements and ageing and potentially unreliable assets).	
Other		
Ergon Energy (pp. 8-9), Energex (p. 3), Victorian DNSPs (p.15), Aurora Energy (p. 6), Essential Energy (p. 5), Endeavour Energy (p. 5)	These stakeholders considered that DNSPs face sufficient business and regulatory drivers to ensure they carry out appropriate planning and produce accurate forecasts in their DAPRs. Examples of the drivers included the requirements of Chapter 6 and the AER's ongoing monitoring activities. The ENA also noted that DNSPs are exposed to financial penalties under the service target performance incentive scheme in the event service standards are compromised in the pursuit of cost reductions. The ENA considered it was in DNSPs commercial interests to ensure an optimal mix of network and non-network solutions were employed.	Noted. See section 6.3.2 for further discussion.
TEC (p.4)	TEC was concerned that DNSPs do not face sufficient incentives to ensure that DAPRs were prepared accurately.	Noted. See section 6.3.2 for further discussion.
Seed Advisory (p.2)	Seed Advisory requested further prescription in the rules requiring DNSPs to provide information on: the basis for projections of estimated embedded generating units; the methodology on which estimates of capacity in sections of the network have been based; and the methodology on which estimates of system security, fault levels and voltage regulation have been based.	The draft rule requires DNSPs to provide in their DAPRs information in respect of the methodologies used in preparing the DAPR, including methodologies used to identify system limitations and any assumptions applied.[457] The Commission considers that the information proposed for inclusion by Seed Advisory may be included by DNSPs, where relevant, under this requirement. However, where such information is not included, the Commission notes that the draft rule requires DNSPs to

457 See draft schedule 5.8.

Stakeholder	Issue	AEMC Response
		provide a contact person who can field queries from any stakeholder on the content of the DAPR. Stakeholders wishing to gain a better understanding of the background to certain information would be encouraged to contact the DNSP directly to explore the matter further.
Energex (p.4)	Energex queried the AEMC's intention with regard to the phrase 'annual planning review' referred to in proposed clause 5.6.2AA(g)(4). It sought further clarification on whether 'review' was intended to refer to the process of producing the DAPR.	No longer relevant. The draft rule removes this clause.
AEMO (p.1)	AEMO noted that the AEMC may wish to consider whether any of the information required in the DAPR could be included in the transmission annual planning reports (TAPR).	Noted. However, the consideration of possible changes to the reporting requirements of the TAPR are beyond the scope of this rule change.
Energex (p.3)	Energex suggested that the AER may find it useful for DNSPs to provide feedback following the first round of DAPRs.	Noted.
Victorian DNSPs (p.8)	The Victorian DNSPs considered that the rules should be drafted to allow for the publication of separate transmission connection planning reports (TCPR) and DAPRs. They considered it would be complicated, specifically for Victoria, if the rules required each DNSP to publish a TCPR within its DAPR.	The draft rule provides DNSPs flexibility in reporting information on transmission-distribution connection points where a DNSP is required to report on these assets under jurisdictional electricity legislation.
Demand side engagement strategy		
ENA (p.6), Ergon Energy (p.6)	The ENA and Ergon Energy considered DNSPs should be able to apply for an exemption or variation to the demand side engagement strategy where, due to operational or resource reasons, the costs of complying would manifestly	The Commission does not support the proposal to allow exemptions or variations to the demand side engagement strategy. The Commission considers that the obligation on DNSPs to provide a demand side engagement document

Stakeholder	Issue	AEMC Response
	exceed any benefit that may be reasonably obtained from compliance.	and demand side engagement register successfully balance the potential benefits of providing information to the market, with the potential costs of preparing the document and establishing the register. The Commission notes that the draft rule does not require DNSPs to establish, maintain and publish a database of non-network proposals and/or case studies as part of the demand side engagement strategy. See section 7.3 for further discussion on this matter.
ENA (p. 6), Ausgrid (p. 3)	The ENA and Ausgrid considered that the most effective way to improve non-network alternatives was through clear and appropriate incentives rather than prescriptive process requirements. Ausgrid noted that in NSW, the D-factor incentive regime is more successful that the NSW Demand Management Code.	The objective of the demand side engagement strategy is to provide transparency around the processes used by DNSPs to engage with non-network providers and consider non-network options. The draft rule is therefore expected to support current, as well as any future, incentives on DNSPs to seek non-network options under regulated price arrangements.
EnerNOC (p. 3)	EnerNOC considered DNSPs would need to be cooperative with non-network providers for the demand side engagement strategy to work in practice. It suggested that this objective could also be achieved through the introduction of a target that DNSPs must use 10 per cent of their capital expenditure towards non-network alternatives.	Noted. The Commission considers that the demand side engagement obligations set out in the draft rule should successfully encourage the engagement of non-network providers in the planning and development process, and provide the basis for the development of on-going working relationships between non-network providers and DNSPs. The Commission therefore does not support the introduction of a target on expenditure as suggested by EnerNOC.
Endeavour Energy (pp. 2-3)	Endeavour Energy did not see the need for a separate demand side engagement strategy given the requirements of the DAPR.	The Commission notes that the DAPR and demand side engagement strategy differ in their objectives. While both provide additional information to the market in respect of DNSP planning activities, the focus of the DAPR is on the identification of system limitations; the focus of the demand

Stakeholder	Issue	AEMC Response
		side engagement strategy is on the development of solutions to address those system limitations.
Demand side engagement document		
Ergon Energy (p. 12)	Energex did not consider the demand side engagement document should contain or replicate information which is or will be publicly available elsewhere (for example, through the Chapter 5A connection process and associated publication requirements established under the NECF). For information available elsewhere, Energex considered a specific reference to that source would be sufficient.	The demand side engagement document is intended to provide comprehensive, standalone guidance on the processes adopted by DNSPs in their management and consideration of non-network proposals. While the Commission recognises that there may be some overlap with information available elsewhere, it nonetheless considers the value of providing the information in a single standalone document is likely to outweigh the costs of any duplication.
Victorian DNSPs (p. 9)	The Victorian DNSPs considered that, on the basis that non-network solutions could defer or avoid the need for augmentation of transmission-distribution facilities, the avoided transmission-distribution connection charges should also be considered in the demand side engagement document.	This information can be included within the demand side engagement document where a DNSP considers it would be beneficial.
Demand side engagement database		
ENA (p. 7), Ergon Energy (pp. 5, 13), Energex (p. 2), Victorian DNSPs (pp. 3, 9, 14), Endeavour Energy (pp. 2-3), Essential Energy (p. 4)	A number of DNSPs did not support the proposal to develop and maintain a database of non-network proposals/case studies. The ENA, Energex and the Victorian DNSPs considered the need to remove confidential information would render the database of very limited value. In addition, Ergon Energy considered that: (1) even though DNSPs would have discretion to select data to be	The Commission agrees with the view that the establishment of a database is unlikely to be the most efficient means of assisting non-network providers in developing non-network proposal that could be developed by DNSPs more efficiently. The draft rule therefore does not require DNSPs to establish, maintain and publish a database of non-network proposals and/or case studies as part of the demand side engagement strategy.

Stakeholder	Issue	AEMC Response
	published on the database, there would nonetheless be a risk of inadvertently disclosing commercially sensitive information; (2) additional resources would be required to administer the database; and (3) the database would result in reporting duplication as details of non-network proposals would be published in the RIT-D project specification report. The ENA noted that the demand side engagement strategy and various documents associated with the RIT-D process sufficiently demonstrated DNSPs commitment to transparency and accountability. The Victorian DNSPs did not consider the existence of the database would in itself increase demand side participation, and would not aid in contributing to the NEO. Endeavour Energy considered the database would be too difficult to implement due to the level of commercially sensitive information. Endeavour suggested that either the rules or an AER Guideline provide a template for this information to minimise commercial sensitivities.	However, in order to provide further transparency around DNSPs non-network assessment processes, additional content requirements have been added to the demand side engagement document requiring DNSPs to provide, where possible, an example of a best practice non-network proposal[458], and a worked example of the assessment process[459], to support existing content. See section 7.3.1 for further discussion on this matter.
Demand side engagement register		
ENA (p. 7), Ergon Energy (pp. 13-14)	The ENA and Ergon Energy did not support the proposal for DNSPs to establish and maintain an individual register of interested parties. The ENA considered this to be an inefficient and costly approach to facilitating information flow between DNSPs	Noted. See section 7.3.1 for further discussion on this matter.

458 Draft schedule 5.9(d).

459 Draft schedule 5.9(l).

Stakeholder	Issue	AEMC Response
	and non-network proponents and suggested a central repository would be more appropriate. Ergon Energy considered the proposal undermined the development of a national market and would increase the burden on non-network providers by requiring them to register separately with each DNSP. Ergon Energy also expressed support for a central registration system for non-network providers, managed by AEMO.	
Endeavour Energy (pp. 2-3)	Endeavour Energy noted that it already maintains a register of interested parties and that the new proposal would create a risk of regulatory burden. Endeavour Energy suggested that some form of national or jurisdictional accreditation for existing processes may be appropriate.	The Commission notes that implementation of the draft rule is not intended to result in the duplication of planning arrangements at the national and state/territory level. Rather, the draft rule assumes that the existing jurisdictional arrangements, to the extent that they are covered by the draft rule, would be rolled back once the national framework is in place.
Other		
Energex (p. 2), Aurora Energy (p. 3), Endeavour Energy (p. 3), Victoria DNSPs (p. 14)	These stakeholders noted that costs associated with implementing the demand side engagement strategy may include additional resources, information technology, publishing tools and businesses processes which would need to be established and maintained. Aurora Energy noted that its customer base would not be willing to pay these costs as they relate to a 'perceived' rather than an 'actual' failure.	Noted.
EnerNOC (p. 4), TEC (p. 4)	EnerNOC and the TEC considered that the benefits of developing a demand side engagement strategy would outweigh the cost of the strategy.	Noted.

Stakeholder	Issue	AEMC Response
	The TEC also noted that the cost of developing the strategy could be passed through or recouped from DSP projects.	
ETSA Utilities (p. 5)	ETSA Utilities questioned the need for the existing definition of 'publish' (set out in Chapter 10 of the NER) to be amended, particularly as a similar obligation to make similar documents available for public inspection had not been applied to TNSPs. Further, ETSA Utilities noted that while it had no objection to making documents available on its website, the requirement to make documents available for public inspection was unnecessary, particularly because such public access facilities do not presently exist.	The Commission recognises these concerns and has amended the definition of 'publish' in the draft rule such that a document would be considered to be published by a DNSP if it is published on the DNSPs website.
ENA (p. 7), Energex (p. 2)	The ENA and Energex suggested the AEMC consider the need to develop a set of eligibility criteria for non-network providers responding to consultation. These stakeholders considered that such criteria would ensure practical solutions were proposed in an efficient manner, by providers who had met the eligibility criteria. These stakeholders also considered that it must be recognised that DNSPs generally have governance arrangements and policies in place which must be adhered to in the procurement of all goods and services, which may conflict with the register of non-network participants.	The Commission does not consider it necessary to develop eligibility criteria for non-network providers responding to consultation at a national level. The Commission notes that DNSPs are not prevented from developing their own set out of eligibility criteria for non-network providers responding to consultation where a DNSP considers that such criteria may assist in determining a non-network providers ability to participant in the process.[460]

460 The demand side engagement document must include a description of a DNSP's process to engage and consult with non-network providers to determine their level of interest and ability to participate in the development process for potential non-network solutions. See draft schedule 5.9.

Stakeholder	Issue	AEMC Response
Joint planning arrangements		
Project assessment process for joint planning projects		
Applicable regulatory investment test		
ENA (p. 10), Ausgrid (p. 5)	The ENA considered that the RIT-D should be applied where the preferred solution to address a distribution constraint was a distribution solution (even though a transmission solution may be an option). The ENA considered that the RIT-T should only be applied where the preferred solution to address a distribution constraint was a transmission solution. Ausgrid endorsed the ENA submission and considered all distribution investments should be subject to the RIT-D.	The Commission supports a single project assessment process - the RIT-T - being applied to all projects which are jointly planned by TNSPs and DNSPs, irrespective of whether the need for investment is driven by a distribution or transmission network limitation. However, the draft rule provides an exception to this general rule for those joint planning projects which may be less likely to deliver material market benefits. In these cases, the benefits of carrying out the RIT-T process rather than the RIT-D process are likely to be minimal. The draft rule therefore requires the RIT-T to be applied to all projects which are jointly planned and where at least one of the credible options to address an identified need includes a network or non-network option on a transmission network with an estimated capital cost greater than $5 million. In other cases, NSPs would have the option of carrying out the requirements of the RIT-D as an alternative to the RIT-T (where the relevant RIT-D criteria are met). See section 8.3.3 for further discussion on this matter.
Energex (p. 5)	Energex did not support the RIT-T being undertaken in all circumstances where expenditure on a transmission network was required. It considered a more practical alternative would be for the RIT-T to be applied only in	Noted. See above.

Stakeholder	Issue	AEMC Response
	instances where there was a material increase in transmission capacity. Where there was a material increase in the distribution network, Energex considered the RIT-D should be applied.	
Ausgrid (p. 5)	Ausgrid noted a lack of clarity in the language used to refer to joint network investments to which the RIT-T would apply. It considered that care would need to be taken to ensure that there was not an expectation that the RIT-T would apply to any investment identified through the joint planning process, but rather only to those investments that affect both the transmission and distribution network or require action by both. In this regard, Ausgrid suggested proposed clause 5.6.5CB(a)(4) be amended.	Noted.
Energex (supplementary submission, pp. 1-3)	Energex queried the benefits, from a policy perspective, of undertaking a RIT-T in circumstances where the purpose of joint planning is to address a distribution network limitation. Energex noted that the RIT-D was designed specifically to cater to the characteristics of distribution networks and, on this basis, provides additional rigour to the consideration of non-network alternatives than the RIT-T. Energex therefore considered that distribution limitations assessed in the context of joint planning (i.e. under the RIT-T) would not be subject to the same level of rigour as provided for by the RIT-D. Energex noted that where a requirement for investment related primarily to a limitation on a distribution network, the lead party would generally be a DNSP. On this basis, it considered the assessment should be conducted under the RIT-D.	Noted. The Commission wishes to clarify that, although different in name, the project specification consultation report required under the RIT-T (for all RIT-T projects) and the non-network investigation report required under the RIT-D (for applicable RIT-D projects) are very similar in respect of the information published for consultation. While the scope of the project specification consultation report is broader than the non-network investigation report (that is, the project specification consultation report requires NSPs to consult on network options and material market benefits), both reports contain information intended to assist the relevant NSPs in considering and assessing possible non-network options. On this basis, the Commission disagrees with the view that joint planning projects subject to the RIT-T will be subject to a less thorough consideration of non-network options than if those projects were assessed under the RIT-D.

Stakeholder	Issue	AEMC Response
Lead party to apply the applicable regulatory investment test		
ENA (pp. 4, 10, 9, 20), ETSA Utilities (p. 5)	The ENA and ETSA Utilities queried whether a TNSP or DNSP would be required to perform the RIT-T in instances where an investment was driven by a distribution constraint. The ENA considered that TNSPs should always be the lead party in these circumstances as DNSPs would not be equipped nor have sufficient resources to undertake the RIT-T in addition to the RIT-D.	The draft rule requires the relevant NSPs to identify a lead party to carry of the requirements of the RIT-T (or RIT-D, where appropriate). The Commission notes that selection of a lead party does not preclude participation by the other parties in the project assessment process. The draft rule requires TNSPs and DNSPs to use best endeavours to work together to achieve efficient planning outcomes and investments. On this basis, the Commission would expect TNSPs and DNSPs to work closely in applying the relevant regulatory investment test to joint planning projects. See section 8.3.3 for further discussion on this matter.
Energex (supplementary submission, pp. 1-3)	Energex did not support the requirement for DNSPs to undertake a RIT-T on the basis that it would create uncertainty and inefficiency in the distribution planning process due to: • differences between the RIT-T and RIT-D. Energex considered it was not prudent for a DNSP to develop the required critical competencies, systems and models to undertake the requirements of the RIT-T; and • uncertainties around how to address some of the RIT-T requirements. Energex considered the uncertainties likely to arise from requiring a DNSP to undertake the RIT-T were sufficient to reconsider the proposed requirements.	Noted. As above.

Stakeholder	Issue	AEMC Response
ETSA Utilities (p. 6)	ETSA Utilities believed further clarity was required in the proposed rule regarding when each test (RIT-T or RIT-D) needed to be performed and by which party (TNSP or DNSP).	Noted. See section 8.3.3 for further discussion on these matters.
Energex (p. 6)	In respect of joint network planning between DNSPs, Energex requested clarification as to which NSP would be required to undertake a RIT-D where there were multiple network owners involved in a single project.	It would be expected that DNSPs would agree on a lead party for carrying out the requirements of the RIT-D. A new clause has been included in the draft rule to clarify this intent. See section 8.3.2 for further discussion on this matter.
Other		
ENA (p. 9)	The ENA noted that joint projects were currently evaluated on the basis of seeking the least cost solution, with issues concerning ownership being a secondary consideration.	The Commission notes that, under the draft rule, joint planning projects assessed under the RIT-T (or RIT-D, where applicable) would be evaluated on a net economic benefit basis, rather than on a least cost basis. Only where relevant parties determine that no classes of applicable market benefits are material would the RIT-T assessment proceed on a least cost basis.
ENA (p. 11)	The ENA considered that, in the majority of cases, an investment resulting from joint planning would not have a material market effect. The ENA considered that a material market effect would only ever likely occur where joint planning leads to reinforcement of the interconnected transmission network to either: (1) ensure a distribution network meets the minimum power system security and reliability standards; or (2) replace distribution assets.	Noted.
Aurora Energy (p. 7)	Aurora Energy considered that the proposed rule did not sufficiently clarify the arrangements where DNSPs may be required to undertake joint planning with other DNSPs. Suggested proposed clause 5.6.2AA(i) contains	Noted. The draft rule includes a number of new clauses intended to provide further clarity around the joint planning obligations of DNSPs and DNSPs. However, the DNSP to DNSP rules are less prescriptive than the joint planning

Stakeholder	Issue	AEMC Response
	information similar to proposed clause 5.6.2AA(h)(2) and (h)(4).	obligations of DNSPs and TNSPs. This matter is discussed further in section 8.3.2.
Regulatory Investment Test for Distribution (RIT-D)		
Regulatory investment test generally		
Identification of credible options		
ENA (p. 17), Energex (p. 11)	The ENA and Energex noted that 'commercially feasible' (referenced in proposed clause 5.6.5D(a)(2)) was undefined and thus may be open to interpretation. These stakeholders suggested this phrase be replaced with 'economically feasible', consistent with the language of the RIT-D principles which refer to net economic benefit (they considered that an option found to have a negative NPV could be argued to be commercially unfeasible).	Noted.
ENA (p. 17), Energex (p. 11)	The ENA and Energex did not consider it appropriate for DNSPs to assess whether a credible option was 'intended to be regulated' as required under proposed clause 5.6.5D(b1)(5). These stakeholders noted that the regulation of services and assets was determined by the AER.	Proposed clause 5.6.5D(b1)(5) (whether the credible option is intended to be regulated) and proposed clause 5.6.5D(b1)(7) (any other reasonable factor the DNSP reasonably considers should be taken into account) have been omitted from the draft rule. The Commission does not consider these matters are relevant to the identification of a credible option under this clause.
Energex (p. 11)	Energex considered it was not clear why, under proposed clause 5.6.5D(b1)(4), an option being a network or non-network option would be relevant to its status as a credible option. Energex submitted it was not clear how network versus non-network was a factor relevant to the assessment of an option against the credible option 'criteria' set out in cl.5.6.5D(a).	As above. Draft clause 5.6.5D(b1) is intended to clarify that an option being a network option or a non-network option should not be relevant to its status as a credible option.

Stakeholder	Issue	AEMC Response
Energex (p. 11)	Energex suggested that proposed clause 5.6.5D(b1)(5) and (6) should not refer to 'credible options' given that, at this stage in the process, a DNSP would have not yet determined whether the option is credible.	No longer relevant due to drafting changes.
Endeavour Energy (pp. 6-8)	Endeavour Energy requested clarification on the meaning of proposed clause 5.6.5CA(b): "...the present value of the net economic benefit to all those who produce, consume and transport electricity in the market".	The RIT-D is intended to capture any cost or benefit which can be measured as a cost or benefit to all those who produce, consume and transport electricity in the market. This definition requires DNSP to take a NEM-wide view in calculating the impacts of a project.
RIT-D principles		
Purpose		
ENA (p.13), Energex (p. 7)	The ENA and Energex noted that the purpose of the RIT-D as stated in the AEMC Final Report was 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." However, they noted that proposed cl.5.6.5CA(b) stated that the purpose of the RIT-D was to "identify the credible option that maximises the present value of the net economic benefit to all those who *produce, consume and transport* electricity". ENA and Energex queried the departure from the original drafting and requested the reasons for the policy departure be made clear.	The purpose of the RIT-D is to identify the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity.
Application of the RIT-D		
AER (p. 5)	Under proposed clause 5.6.5CA(c)(1), the RIT-D must require a comparison of reasonable scenarios if each	The draft rule provides the AER with discretion to specify in the RIT-D the appropriate form of cost-benefit analysis to

Stakeholder	Issue	AEMC Response
	credible option were implemented "compared to a situation where no option was implemented". The AER noted that for projects driven by reliability corrective action, this approach may require a level of analysis which is unnecessary given that a "do nothing" option was not feasible. In these circumstances, the AER noted that, arguably, the relative ranking of each of the options was more important than the absolute values of the net economic benefits for each option. The AER considered further thought should be given to whether it is necessary to develop a do nothing option scenario in circumstances where reliability requirements mean that doing nothing is not plausible.	apply in relation to projects driven by reliability issues and projects driven by the achievement of market benefits. See draft clause 5.17.1(a).
Ausgrid (p. 11)	In respect of proposed clause 5.6.5CA(c), Ausgrid noted that distribution planning does not generally require the identification of alternative scenarios of demand growth and development which is a characteristic of transmission developments. It considered the requirement for a RIT-D to develop and consider alternative scenarios was inappropriate and disproportionate to the outcomes of such analysis. Ausgrid considered that from a distribution planning perspective, it would be more appropriate to take a sensitivity analysis approach to demand forecasts.	Noted. As above, see draft clauses 5.17.1(a) and (b). In addition, the Commission considers that it is appropriate for the AER to consider this issue in the context of the AER's development of the RIT-D and RIT-D application guidelines.
ENA (pp. 12-13), Energex (p. 7)	The ENA and Energex noted that proposed clause 5.6.5CA(c)(4) would require DNSPs to consider the value of customer reliability (VCR) when assessing market benefits under the RIT-D. Given that AEMO is currently consulting on VCR for TNSPs, these stakeholders suggested that the AEMC recommend that AEMO undertake a similar consultation for DNSPs so the classes	The Commission notes that these issues are being considered in the context of the AEMC's review of distribution reliability outcomes and standards.[461]

461 See: www.aemc.gov.au.

Stakeholder	Issue	AEMC Response
	of market benefits that could be delivered by the credible option may be better calculated.	
ENA (p. 14), Energex (p. 8)	The ENA and Energex considered that further clarity was required in relation to the consideration of non-financial costs by DNSPs. These stakeholders considered clarification would assist DNSPs in dealing with increasing number of community disputes around the scope of costs, and non-financial costs specifically. The ENA and Energex suggested the AEMC include a 'for the avoidance of doubt' provision to this affect at the end of proposed clause 5.6.5CA(c)(6), or amend proposed clause 5.6.5CA(c)(9) (which would arguably exclude 'non-financial' costs in any case).	The draft rule clarifies that, in considering costs incurred in constructing or providing a credible option, only financial costs are relevant.
AER (p. 6), ENA (p. 14), Energex (p.8)	The AER noted that it was not clear why proposed clause 5.6.5CA(c)(7) (which does not have an equivalent provision in the RIT-T) was beneficial or necessary. It considered it was difficult to imagine circumstances in which construction costs, operating and maintenance costs and costs associated with complying with regulatory arrangements would not apply to a particular credible option. In addition, the AER noted that DNSPs had experience in quantifying these classes of costs as they are broadly the same as those that currently apply under the reliability limb of the existing regulatory test. The ENA and Energex noted that proposed clause 5.6.5CA(c)(7) would require a DNSP to include a quantification of all classes of applicable costs unless it could provide reasons as to why a particular class of cost 'is not expected to apply'. These stakeholders considered the wording was unclear and suggested it be replaced with a reference to the 'materiality' of the class of cost, in line	The Commission broadly agrees with these views. On this basis, proposed clause 5.6.5CA(c)(7) has been omitted from the draft rule and a consequential amendment made to draft clause 5.17.1(c)(6) to require DNSPs to consider and quantify the applicable classes of costs.

Stakeholder	Issue	AEMC Response
	with the wording of the corresponding provisions for the RIT-T.	
Ergon Energy (p. 16)	Ergon Energy considered there was an inconsistency in proposed clause 5.6.5CA(c)(7) and (9) relating to costs which cannot be quantified. In addition, Ergon Energy noted that, in some cases, it would be difficult to quantify certain classes of costs. Ergon Energy recommended that this clause be amended to require DNSPs to include quantification, to the extent reasonably possible, of all classes of relevant costs.	As noted above, proposed clause 5.6.5CA(c)(7) has been omitted from the draft rule. In addition, the Commission does not consider the amendment suggested by Ergon Energy is necessary on the basis that DNSPs have experience in quantifying the specified classes of costs in the context of the regulatory test. In addition, the Commission notes that the RIT-D application guidelines will include methodologies for valuing the costs of credible options. This should assist DNSPs in quantifying relevant classes of costs.
ENA (p. 14), Energex (p. 8)	The ENA and Energex considered the use of the term 'may not' in proposed clause 5.6.5CA(c)(9) was ambiguous and suggested this be replaced with 'will not'. These stakeholders considered such an amendment may prevent unnecessary disputes being raised.	Noted. Reference to 'may not' has been replaced with reference to 'will not' in the draft rule.[462]
ENA (p. 14), Energex (p. 8)	The ENA and Energex noted that proposed clause 5.6.5CA(c)(9) allowed market benefits or costs to 'Market Customers' to be included in RIT-D analysis which was inconsistent with the corresponding provision in relation to the RIT-T. These stakeholders queried whether there was a reason for the difference, and whether it would be practical for a DNSP to consider benefits to Market Customers.	The RIT-D is intended to capture any cost or benefit which can be measured as a cost or benefit to those who produce, consume and transport electricity in the market. On the basis that any relevant 'Market Customers' would be captured under the 'consumers of electricity' category in this clause, reference to 'Market Customers' has been removed from the draft rule.
Ergon Energy (p. 16)	Ergon Energy noted that the wording of proposed clause 5.6.5CA(c)(4) appeared to require a DNSP to undertake a	The Commission notes that it was not the intention of proposed clause 5.6.5CA(c)(4) to require DNSPs to

462 Draft clause 5.17.1(c)(8).

Stakeholder	Issue	AEMC Response
	compulsory assessment of market benefits. On the basis of the view that the majority of distribution projects would be reliability driven (and hence the consideration of market benefits irrelevant), it considered that the compulsory assessment of market benefits would add considerably to the costs of the process with no real benefit.	undertake detailed analysis and quantification of each class of market benefit when considering whether market benefits could be delivered by a credible option. Rather, it was intended that any consideration of market benefits be qualitative in nature only. Draft clause 5.17.1(c)(4) clarifies this intent.
Ergon Energy (p. 16)	For projects where market benefits are determined to be relevant, Ergon Energy expressed support for the development of an agreed jurisdictional based standard approach to valuing the upstream benefits to transmission and generation.	Noted. The Commission considers that it is more appropriate for the AER to consider this issue in the context of the AER's development of the RIT-D and RIT-D application guidelines.
Energex (p. 8)	In relation to the use of the term 'plant' in proposed clause 5.6.5CA(c)(4), Energex noted that the definition of 'plant' in Chapter 10 appeared to refer to plant relevant to generation. Energex suggested that the AEMC clarify what this term referred to in relation to distribution.	The definition of ‘plant’ set out in the proposed rule includes several definitions, not all of which are generation specific, and any of which may be relevant to the application of the RIT-D.
Energex (p. 8), AER (pp. 5-6)	Energex noted that proposed clause 5.6.5CA(c)(4)(viii) would require DNSP to consider "any other benefits that the DNSP determines to be relevant". Energex considered it was unclear what other benefits would be included and suggested that if there are none, the clause should be removed. However, in the event the provision was retained, Energex suggested the AER be required to provide examples of what other market benefits would be deemed relevant in the application guidelines. The AER noted that the drafting of this clause differed from the equivalent clause in the RIT-T without sound reason. It argued that it was not appropriate for TNSPs to propose additional classes of market benefits and costs that were not already specified in the rules or the RIT-T itself, as doing so may lead to an inconsistent approach to the	The Commission notes that the RIT-D process, unlike the RIT-T process, does not require DNSPs to prepare a project specification consultation report for all distribution projects subject to the RIT-D. In addition, while DNSPs are required to prepare a non-network options report for certain projects, there is not a requirement for DNSPs to consult on the relevance or materiality of market benefits in that report (although DNSPs may do so if they consider it appropriate). Therefore, given the absence of a mechanism to ensure the orderly introduction of other classes of market benefits into the RIT-D, and the absence of a process for consultation on their relevance and materiality, the Commission does not consider it appropriate to provide DNSPs with an opportunity to introduce additional classes

Stakeholder	Issue	AEMC Response
	development of the RIT-D. The AER suggested a preferable approach would be to permit the AER to set out additional classes of market benefits or costs in the RIT-D and then limit the addition of any further classes of market benefits. Further, in the instance the AEMC determined it was appropriate for DNSPs to proposed addition classes if costs and benefits, the AER considered the rules should require a DNSP to obtain written prior agreement from the AER.	of market benefits into the RIT-D. The draft rule therefore removes this provision and includes a new provision providing the AER with discretion to add to the list of market benefits, where appropriate.
Copper Development Centre (p. 2)	CDC expressed support for the requirement that DNSPs give consideration to changes in electrical energy losses in their major investment decisions. In addition, the CDC requested that the AEMC add a requirement that the AER provide guidance on a methodology for valuing the cost of losses as part of the RIT-D in its application guidelines. Specifically, the CDC suggested adding the following sub-clause to proposed clause 5.6.5CA(h)(3): "an appropriate methodology for valuing the long-run costs of electrical energy losses".	Noted. The Commission considers that this proposal is already captured under the requirement for the AER to provide guidance and worked examples in the RIT-D application guidelines on the classes of market benefits listed in the rules. These classes of market benefits include changes in electrical energy losses. See draft clause 5.17.2(c)(4).
Endeavour Energy (pp. 6-8)	Endeavour Energy considered the RIT-D parameters did not recognise that DNSP investments are made on the basis of capacity, but that cost recovery is made on the basis of energy sales. Endeavour Energy suggested that this issue could be addressed in the AER application guidelines.	Noted. The Commission considers that it is more appropriate for the AER to consider this issue in the context of its development of the RIT-D and RIT-D application guidelines.
Energex (p. 18)	Energex noted that in carrying out the RIT-D economic assessment, some investment options may have a credit for recovered plant that could be used as part of a different augmentation. Energex suggested that the AEMC confirm that credits for recovered plant should be allowed against the respective option.	The RIT-D requires that a RIT-D proponent consider and quantify the costs incurred in constructing or providing a credible option. If a credit for recovered plant influences the cost of constructing or providing a credible option, then the Commission would expect this credit to be taken into account in the RIT-D assessment.

Stakeholder	Issue	AEMC Response
Projects subject to the RIT-D		
RIT-D cost threshold		
ENA (pp. 4, 13, 15), Ergon Energy (pp. 4-5), Energex (pp. 9, 15), Victorian DNSPs (pp. 5, 16), ETSA Utilities (pp. 6-8)	These stakeholders expressed concern in relation to the application of the RIT-D threshold to "the most expensive option which is technically and economically feasible". They considered that this requirement would lead to almost every distribution investment being subject to the RIT-D. The ENA, Ergon Energy and Energex considered the proposed approach would create a regulatory burden on DNSPs as: (1) the term 'economically and technically feasible' could be broadly interpreted and would capture a range of possible options, thus increasing the likelihood of the most expensive option being above $5 million; and (2) such terminology would essentially prescribe a requirement to undertake a preliminary mini least cost regulatory investment test prior to the STT stage of the RIT-D. The ENA and Energex suggested the focus of the RIT-D cost threshold should be on the least expensive option. This view was supported by Ergon Energy who considered that either the 'least expensive option' or the 'preferred option' should be the focus. ETSA Utilities and the Victorian DNSPs considered the RIT-D cost threshold should be set with reference to the capital cost of the 'preferred network investment option'.	The draft rule differs from the proposed in respect of the terminology used to describe the approach to applying the RIT-D cost threshold level. Under the draft rule, a project will be exempt from the RIT-D where the estimated capital cost (to the NSPs affected by the RIT-D project) of the most expensive credible option[463] is less than $5 million (as varied in accordance with a cost threshold determination). See section 9.3.2 for further discussion on this matter.

463 'Potential credible option' is defined in the draft rule as an investment option which a RIT-T proponent or a RIT-D proponent (as the case may be) reasonably considers has the potential to be a credible option based on its initial assessment of the identified need.

Stakeholder	Issue	AEMC Response
Victorian DNSPs (supplementary submission, pp. 1-2)	The Victorian DNSPs considered that application of the RIT-D cost threshold to the 'most expensive' technically and economically feasible option was unworkable and would not serve to effectively or meaningfully limit projects which would be subject to the RIT-D. The Victorian DNSPs considered that a more appropriate and workable approach would be to apply a 'least expensive option' to all 'credible options'. They did not consider that the most expensive credible option would be any more workable than the current proposal.	Noted. The Commission considers that the application of the RIT-D cost threshold level (being $5 million) to the most expensive potential credible option provides the appropriate balance between minimising the regulatory burden placed on DNSPs in conducting the RIT-D process, and ensuring that the appropriate range of projects are subject to a robust and transparent economic assessment. See section 9.3.2 for further discussion on this matter.
Essential Energy (p. 7)	Essential Energy considered there was a lack of clarity in the reference to "the most expensive option to address the relevant identified need which is technically and economically feasible". It considered this provision would more meaningfully relate to the 'credible option' definition and use.	The Commission considers there is merit in this suggestion and has clarified the terminology used to describe the approach to applying the RIT-D cost threshold to this effect. See section 9.3.2 for further discussion on this matter.
Ergon Energy (p. 18)	Ergon Energy considered that the term ‘economically feasible’ (referred to in proposed clause 5.6.5CB(a)(2)) should be clarified on the basis that it was open to interpretation and hence fraught with risk given introduction of the dispute resolution process. Ergon Energy also considered that it would be difficult to quantify marginal benefit if ‘economically feasible’ was intended to mean 'marginal benefit exceeds marginal cost'.	Noted. As above.
AER (p. 6)	The AER noted support for the proposed $5 million RIT-D cost threshold on the basis that it provided consistency with the RIT-T and was sufficiently high that it would not create a significant RIT-D assessment burden on DNSPs.	Noted.

Stakeholder	Issue	AEMC Response
ENA (p. 15), Endeavour Energy (pp. 6-8), Victorian DNSPs (pp. 5, 16)	These stakeholders queried whether the $5 million RIT-D cost threshold level was appropriate. Endeavour Energy considered that $5 million was too low and requested further consultation on the matter. The Victorian DNSPs considered that the threshold level should be no lower than $5 million.	Noted. See section 9.3.2 for further discussion on this matter.
Ergon Energy (p. 9)	Ergon Energy considered that the RIT-D design parameters were an improvement on current arrangements and consistent with the NEO.	Noted.
Exempt projects		
ENA (pp. 16-17), Ergon Energy (pp. 5, 17), ETSA Utilities (pp. 6-8)	The ENA advocated the exclusion of several other classes of distribution investment from the scope of RIT-D, including the following: 1. Support services, such as IT and communications equipment. 2. "S Factor" proposals.[464] 3. Projects where the principal driver for the distribution investment is to address either a safety related issue, environmental threat or statutory requirement.[465]	See section 9.3.2 for further discussion on the type of projects intended to be subject to the RIT-D project assessment process.

464 The ENA noted that these projects were initiated to improve the reliability of the network and are essentially self-funding, assessed on the basis of a business case using the DNSP's specific internal investment criteria.

465 The ENA noted that, where such projects exist, no non-network solutions would exist to eliminate the risks and absolve DNSPs of their general duty of care to staff or the public or in general their statutory requirements.

Stakeholder	Issue	AEMC Response
	Similarly, Ergon Energy considered the RIT-D should not apply to investments undertaken: 1. as a result of legislative compliance obligations (duty of care); 2. where an investment is primarily an aged asset replacement but which inadvertently results in an augmentation component due to the inability to acquire the same size aged asset because of changes in design standards of infrastructure availability; 3. gifted or contributed assets regardless of whether they are funded by a third party and gifted to DNSP or the third party pays the DNSP to undertake the work; 4. where the requirement stems from need to connect a new customer of upgrade/change customer supply (at customers request). ETSA Utilities also suggested an expansion of proposed clause 5.6.5CB to exempt duty of care projects from the RIT-D process.	
ENA (pp. 15-16), Energex (p. 7), Ausgrid (pp. 6-8), ETSA Utilities (pp. 6-8)	The ENA and Energex were concerned that the intention of proposed clause 5.6.5CB(a)(6) was to require the RIT-D to be undertaken on new investments where there was an incidental augmentation or gifted asset required to facilitate a new connection. They considered such a requirement would result in undue delay for the connection asset customer.	The draft rule provides an exemption from the RIT-D for projects where the identified need can only be addressed by expenditure on a connection asset. For clarification, 'connection assets' are assets which provide an entry or exit service at a single connection point.[466] It is intended that any upgrade to the shared network to

466 See Chapter 10 of the NER.

Stakeholder	Issue	AEMC Response
	Ausgrid noted that an unintended consequence of the proposed rule was that some connection assets may be considered as shared network assets and therefore could become the subject of a RIT-D. Ausgrid considered this would result in unnecessary connection delays. Ausgrid also suggested that where a customer contributed a significant proportion of the cost of a new network investment associated with its connection, that investment should be exempt from the RIT-D process. ETSA Utilities requested clarification on the intention of proposed clause 5.6.5CB(a)(6) on the basis that it implied that any portion of a shared network upgrade to support a connection would be subject to a RIT-D. ETSA Utilities suggested a waiver clause like the that included in proposed clause 5.6.5CB(a)(8), be inserted.	support a new connection will fall within the scope of the RIT-D to the extent that expenditure on the upgrade is made by a DNSP and recovered from all users of the network. In the instance that a proportion of an upgrade was fully or partially funded by a customer, that proportion of the upgrade would be excluded from the project for the purposes of the RIT-D assessment (including from consideration of the project against the RIT-D cost threshold).
Ergon Energy (p. 15)	Ergon Energy noted that proposed clause 5.6.5C(a)(8) stated that transmission-to-distribution network connections would not be subject to the RIT-T. It considered this appeared to be contrary to the MCE's intention that *"...the RIT-T would be applied to any investments identified through the joint planning process that affect both the transmission and distribution networks or require action by both DNSPs and TNSPs, including transmission-distribution connection projects"*.[467]	To clarify, under draft clause 5.16.3(6) a RIT-T proponent is not required to apply the RIT-T to a RIT-T project where the identified need can only be addressed by expenditure on a 'connection asset' (as defined in Chapter 10 of the NER). For the purposes of new Chapter 5 Part B, the draft clause 5.10.2 clarifies that a 'transmission-distribution connection point' means the agreed point of supply established between a transmission network and a distribution network.
Energex (p. 10)	Energex considered it was unclear how fault level constraints triggered by the connection of non-network solutions should be treated under the RIT-D. That is,	For an investment option to be considered a credible option, it must (among other things) be able to address an identified need. If, in order to address an identified need,

467 See MCE, Rule Change Request, p.4.

Stakeholder	Issue	AEMC Response
	whether they should be treated as shared network augmentations subject to RIT-D or whether they should be attributed to the last non-network provider which exceeded limits. If the latter was the intention, Energex suggested the AEMC clarify what decision mechanism should be utilised when multiple non-network providers are progressing simultaneously.	an investment option requires supporting investment, then both components would make up a credible option for the purposes of assessment under the RIT-D. In addition, the Commission notes that arrangements for the recovery of costs will depend on how services and assets are regulated. The Commission notes that this is a matter for the AER.
Ausgrid (pp. 6-8)	Ausgrid expressed concern that the scope of projects subject to the RIT-D process was uncertain and potentially much broader than intended. It considered that the expansion of the RIT-D to cover investments other than augmentation had significant consequences with respect to the regulatory burden in performing analysis and demonstrating compliance. Ausgrid suggested that the AEMC redraft the relevant provisions to ensure that only the intended types of investment are subject to the RIT-D.	Noted. See section 9.3.2 for clarification on the type of projects intended to be subject to the RIT-D project assessment process.
AER (p. 6)	The AER supported the inclusion of obligations requiring that DNSPs not treat different parts of an integrated solution to an identified need as distinct and separate options for the purpose of identifying when the RIT-D applies. The AER considered this provision addressed concerns that DNSPs may divide distribution projects into smaller projects to avoid triggering RIT-D.	Noted.
ETSA Utilities (pp. 6-8)	ETSA Utilities requested confirmation on whether the RIT-D cost threshold would apply to all projects.	The RIT-D cost threshold would be applicable to all projects which are not exempt from the RIT-D under draft clauses 5.17.3(a)(1),(3)-(6).

Stakeholder	Issue	AEMC Response
Urgent and unforeseen network issues		
ENA (p. 16), Ergon Energy (p. 18), Essential Energy (p. 7), ETSA Utilities (pp. 6-8), Victorian DNSPs (p. 5), Victorian DNSPs (supplementary submission, p. 2)	These stakeholders considered that the timeframe of six months in the definition of urgent or unforeseen proposed investment was unrealistic. The ENA considered this timeframe was problematic given the lead times required for procurement of equipment, design and construction. The ENA suggested that, rather than prescribe a more appropriate timeframe, urgent and unforseen work should fall within the exemptions framework. Ergon Energy considered the timeframe for an urgent and unforeseen solution to be in service should at least equate to the longest potential timeframe under the RIT-D process (that is, from identifying the need to end of period for a dispute being raised). On this basis, Ergon suggested 12 months would be appropriate. The Victorian DNSPs and Essential Energy also suggested that a minimum timeframe of 12 months would be more reasonable. ETSA Utilities considered the timeframe would be closer to 24 months than 6 months. Ergon Energy also considered the term ‘required to be operational’ should be changed to ‘required to be commenced’ on the basis that the requirement for an investment to be ‘operational’ was not workable. Ergon Energy also considered that the proposed wording would fail to capture projects that needed to commence earlier than the time taken to complete the RIT-D process (even if not operational) to ensure reliability and system criteria were met.	Noted. The Commission considers the requirement for an investment to be operational within six months of the problem being identified in the definition of 'urgent and unforeseen network issue' is appropriate given the circumstances and types of projects intended to be captured by the provision. To clarify, it is intended that this exemption be used rarely and only where the need for investment results from unanticipated and extenuating circumstances, for example, extreme weather. It is not intended that the exemption be used by DNSPs in the place of accurate and timely planning practices. See section 9.3.2 for further discussion on this matter.

Stakeholder	Issue	AEMC Response
AER (p. 8)	The AER noted it would be rare for a distribution project greater than $5 million to be urgent or unforseen. Given this, the AER was supportive of the proposed limitations on exemptions from the RIT-D for urgent and unforeseen projects. The AER considered that these provisions would ensure that DNSPs could not exclude projects from RIT-D due to errors or deficiencies in DNSPs own planning arrangements. The AER also considered these provisions would restrict any gaming opportunities for a DNSP to delay project planning to avoid RIT-D assessment process.	Noted.
Replacement and refurbishment investments		
ENA (pp. 15-16), Energex (p. 10)	The ENA and Energex requested further clarification as to whether proposed cl.5.6.5CB(a)(8) excluded incidental augmentation from the RIT-D process. They suggested that the proposed clause be amended as follows: '*the proposed distribution investment is related to the refurbishment or replacement expenditure of existing assets and also results in an augmentation to the network…*'.	To clarify, under the draft rule, RIT-D projects which involve like-for-like replacement expenditure would be exempt from assessment under the RIT-D. However, where such projects also require (or result in) an augmentation to a network, DNSPs will be required to apply the RIT-D cost threshold to the augmentation component to determine whether the additional expenditure should be subject to the RIT-D project assessment process.
Energex (p. 10)	Energex suggested that the AER provide a worked example of the calculation to be used when determining the augmentation component of a replacement/refurbishment project. Energex considered this would provide greater clarity in relation to these types of investments.	The Commission considers that it is more appropriate for the AER to consider this issue in the context of its development of the RIT-D and RIT-D application guidelines.[468]

468 The draft rule requires the AER to develop and publish the RIT-D and RIT-D application guidelines in accordance with the distribution consultation procedures set out in Chapter 6 of the NER. These procedures include a requirement for the AER to invite submissions on the relevant documents (in this case the RIT-D and associated guidelines).

Stakeholder	Issue	AEMC Response
RIT-D procedures		
Specification threshold test		
ENA (pp. 4, 18), Energex (p. 13), Ausgrid (pp. 6-8), Essential Energy (p. 7), ETSA Utilities (pp. 6-8)	The ENA, Energex and ETSA Utilities considered the proposed drafting required further clarity regarding which projects were intended to be streamlined through the RIT-D process. These stakeholders considered that the phrase 'technically feasible' would result in DNSPs never being able to exercise the STT, rendering it ineffective. The ENA and Energex suggested that 'technically feasible non-network options' be amended to 'credible non-network options' on the basis that this would require non-network options to be economically/commercially and technically feasible and be able to be completed in a timely manner. The ENA and Energex argued that this amendment was the original intention. Ausgrid requested the inclusion of more refined criteria than 'technically feasible' to determine when consultation on non-network options was considered appropriate. Ausgrid suggested guidance could be taken from the NSW Demand Management Code of Practice for Electrical Distribution. Essential Energy considered the intent and application of the STT should be consistent with the demand side engagement strategy.	Noted. The draft rule differs from the proposed rule by providing DNSPs with an exemption from the requirement to prepare and publish a non-network options report (previously the project specification report) where there are reasonable grounds to determine that a non-network option will not be a credible option to address an identified need. The Commission considers the draft rule achieves the original intent of the specification threshold test. See section 9.3.3 for further discussion on this matter.
Ergon Energy (p. 21)	Ergon Energy recommended that proposed clause 5.6.6AB(d) and (f) be amended on the basis that a non-network alternative would only be considered if more	Noted. As above.

Stakeholder	Issue	AEMC Response
	cost effective than the network option.	
ETSA Utilities (pp. 6-8)	ETSA Utilities queried why the specification threshold test was required for projects greater than $10 million given that, under the proposed rule, DNSPs would be required to prepare a draft and final project assessment report for these projects.	The non-network options report, and draft and final project assessment reports, differ in their objectives. The purpose of the non-network options report (previously the project specification report) is to provide DNSPs with a formal opportunity to seek further information from interested stakeholders on possible non-network options for all RIT-D projects where a non-network option may offer a credible alternative to network investment. This will help to ensure that all potential non-network options are identified and considered in the RIT-D process. In contrast, the purpose of the draft and final project assessment reports is to provide transparency in respect of a RIT-D proponent's decision making process. This will promote greater consultation with, and encourage participation by, interested stakeholders in the network planning process.
Energex (p. 13)	Energex submitted that the AER should be required to provide examples in the RIT-D application guidelines of non-network options which would not be technically feasible. Energex considered that such examples would provide guidance to DNSPs as to when a DNSP could utilise the streamlined process.	The Commission notes that the draft rule will require the AER to include in the RIT-D application guidelines guidance on how to make a determination under the non-network screening process.[469]
Project specification stage		
Ergon Energy (p. 23), Victorian	Ergon Energy considered the minimum four month period referred to in proposed cl.5.6.6AB(l) was unnecessarily	The Commission considers the minimum four month timeframe provides an appropriate balance between

469 Draft clause 5.17.4(c)(1).

Stakeholder	Issue	AEMC Response
DNSPs (p. 5)	long. It suggested this period be amended to 12 weeks. The Victorian DNSPs considered this time period would delay projects and limit DNSPs' ability to respond to market changes.	ensuring stakeholders have sufficient time to respond to the non-network options report (including preparing formal non-network proposals for consideration by DNSPs), and avoiding unnecessary delays to investment projects.
Energex (p. 14)	Energex was concerned that without an amendment to proposed clause 5.6.6AB(k), DNSPs would be obligated to publish all information which may be considered preliminary or supplementary information, to help manage the risk that a dispute may be raised at a later stage regarding its provision. Energex also noted that DNSPs were subject to jurisdictional obligations regarding transparency under the Government Owned Corporation framework, Public Records Act and Right to Information Legislation.	Proposed clause 5.6.6AB(k) has been omitted from the draft rule. The Commission notes that interested stakeholders will be provided with an opportunity to participate in the RIT-D project assessment process for certain RIT-D projects and will be able to dispute matters set out in the final project assessment reports for all RIT-D projects (in accordance with the rules). On this basis, the Commission considers there are sufficient incentives for DNSPs to provide relevant preliminary or supplementary information to assist interested stakeholders to engage constructively in the consultation process without the need for an explicit provision in the rules.
Ausgrid (p. 12)	Ausgrid considered that proposed clauses 5.6.6AB(h)(5)(iii), (iv) and (v) were not appropriate for distribution and should be removed.	The Commission notes that the technical characteristics set out in these clauses are provided as examples only.
Energex (p. 14), Ergon Energy (p. 22)	Energex considered it was unclear what was meant by the phrase 'relevant annual deferred augmentation charge associated with the identified need' in proposed clause 5.6.6AB(h)(3). It requested further clarity on this point. Ergon Energy did not support the requirement under proposed clause 5.6.6AB(h)(3) to publish an annual deferred augmentation charge. It considered that doing so would provide non-network providers with information that	To clarify, 'annual deferred augmentation charge' refers to the value of any deferral in a network solution from the implementation of a non-network solution. The draft rule provides that DNSPs would only be required to publish the relevant annual deferred augmentation charge, where available.

Stakeholder	Issue	AEMC Response
	may inflate responses on true costs of supply. Ergon Energy suggested a potential compromise could be the publication of a range of the relevant annual deferred augmentation charges.	
Ergon Energy (p. 23), Endeavour Energy (pp. 6-8)	These stakeholders did not support the requirement under proposed clause 5.6.6AB(h)(7) to state the capital and operating costs of various proposed options. Endeavour Energy considered that doing so may lead to inappropriate and excessive costing of non-network options. Ergon Energy considered this would be commercially sensitive information and opposed by non-network providers.	The draft rule requires DNSPs to include in the non-network options report the total indicative cost (including capital and operating costs) for each potential option to address the identified need. The requirement is drafted such that one inclusive figure may be published and only the indicative cost(s) are required.
Ergon Energy (pp. 22-23)	Ergon Energy recommended that proposed clause 5.6.6AB(h)(4) and (6) be amended as a non-network alternative would only be considered if it is more cost effective than the network option. Further, in respect of proposed cl.5.6.6AB(h)(6), considered that publication of non-network alternatives will raise confidentiality concerns of non-network providers.	Noted.
Project assessment stage		
ENA (p. 19), Energex (pp. 15-16), Endeavour Energy (pp. 6-8)	These stakeholders noted that proposed clause 5.6.6AB(m)(2) would enable the AER to extend the 12 month period within which a DNSP elects to proceed with a proposed investment. The ENA and Energex queried what would happen in the instance the AER rejected an application to extend the 12 month period. That is, whether a DNSP would be required	Noted. The draft rule specifies that the timeframe within which a DNSP would be required to publish its draft project assessment report may be extended beyond the required 12 month period if agreed to in writing by the AER. The 12 month period would commence from the end date of the consultation period for the non-network option report or the publication of the notice under draft clause 5.17.4(d), as relevant.

Stakeholder	Issue	AEMC Response
	to undertake another RIT-D. Energex considered the AER's application guidelines should specify situations in which it would grant such an exemption. Endeavour Energy requested clarification on the starting reference of the 12 month period and noted that long time lags for the final project assessment report may compromise the DNSPs responsibility to maintain supply to customers.	In the instance the AER rejected a DNSPs request for an extension of the 12 month period, we would expect the AER to specify the required course of action at that time.
ENA (p. 19), Energex (pp. 15-16)	The ENA and Energex considered proposed clause 5.6.6AB(m) was ambiguous. The ENA questioned whether the time periods referred to the proceeding of the investment or the preparation of the draft project assessment report. In addition, Energex noted its concern that references to 'elect to proceed' would be made prior to finalisation of the RIT-D process. Energex considered that, if this clause acknowledged that an investment may need to commence prior to finalisation of the RIT-D, then it also provided strong reason to narrow the scope to raise disputes.	The draft rule clarifies that if one or more NSPs wish to proceed with a RIT-D project following a determination under the non-network screening process or the publication of a non-network options report, then the RIT-D proponent, having regard (where relevant) to any submissions received on the non-network options report, must prepare and publish a draft project assessment report within: • 12 months of: — the end of the consultation period on a non-network options report; or — where a non-network option report is not required, the publication of a notice to this effect; or • any longer time period as agreed in writing by the AER.
Energex (p. 16)	Energex considered that the requirement (set out in proposed clause 5.6.6AB(r)) for a DNSP to meet with parties where two or more parties request it was unreasonable given the potentially broad scope of	Noted. This requirement has been omitted from the draft rule. However, the draft rule includes a new provision requiring DNSPs to include in their draft project assessment report the contact details for a suitably

Stakeholder	Issue	AEMC Response
	interested parties and parties on the demand side engagement register. Energex considered that consultation via the submission process should be sufficient.	qualified staff member to whom queries on the draft report may be directed.
Energex (p. 17), Endeavour Energy (pp. 6-8)	Energex and Endeavour Energy considered proposed clause 5.6.6AB(x) was unclear as it did not appear to contemplate the requirement to publish a final project assessment report in instances where the RIT-D was fast tracked. Energex submitted that the AEMC clarify this clause and provide guidance on what should be included in the final project assessment report in these instances.	The draft rule clarifies that, if a RIT-D project is exempt from the draft project assessment report on the basis of a RIT-D proponent having determined that a non-network options report is not required, the RIT-D proponent must publish the final project assessment report as soon as practicable after the publication of the notice. The draft rule also clarifies that if no draft project assessment report is prepared, a final project assessment report must include the matters specified for inclusion in a draft project assessment report.
Energex (p. 17)	Energex suggested that the option to publish the final project assessment report in the DAPR as set out in proposed cl.5.6.6AB(v) may be unrealistic given that the dispute resolution process would therefore not commence until the DAPR was published. Energex considered it would be unlikely that any DNSP would take that risk.	Noted. The Commission considers DNSPs should be provided with this option on the basis that it would provide a useful mechanism to reduce compliance costs for smaller projects where the publication date for a DAPR coincides with the completion of a RIT-D project assessment.
AER review and audit activities		
ENA (p. 16), Energex (p. 10)	The ENA and Energex considered it was unclear why the AER would be required to audit a DNSP's consideration of non-network alternatives. If the requirement is retained, these stakeholders suggested that the AEMC or AER clarify what would be considered an 'adequate consideration of non-network solutions'.	Noted. The Commission considers that the proposed review and audit activities are already captured under the AER's existing functions and powers set out in legislation in relation to monitoring, investigation and compliance. In addition, the Commission does not consider it is appropriate for the rules to prioritise the AER's compliance and enforcement activities. For these reasons, the draft rule does not include this obligation. See section 9.3.5 for further discussion on this matter.

Stakeholder	Issue	AEMC Response
Ergon Energy (p. 19), Energex (p.18), Victorian DNSPs (p. 16), Ausgrid (pp. 6-8), Endeavour Energy (p. 9), Essential Energy (p. 7), Aurora Energy (p. 8)	These stakeholders did not believe it was necessary to provide the AER with additional review and audit powers given that these activities would be captured by the AER's existing functions and powers set out in legislation in relation to monitoring, investigating and enforcing compliance. Ergon Energy considered the prima facie position should be that a DNSP's policies and procedures are fully compliant with rules and the prerequisite should be that AER has valid reason for reviewing a DNSP's policies and procedures - for example, in response to a legitimate dispute or as part of a planned compliance program. Energex was opposed to the proposal to provide the AER with additional audit powers on the basis that the framework in which DNSPs identify and determine these projects is examined by the AER as part of each regulatory determination. Endeavour Energy considered the AER's existing powers of review through the dispute resolution process were appropriate and sufficient.	Noted. As above.
AER (p. 8), TEC (p. 5), EnerNOC (p. 6)	These stakeholders were supportive of the proposal to enable the AER to review DNSPs policies and procedures to determine if non-network alternatives have been duly considered. In addition, the AER noted support for the proposal to allow the AER to conduct audits to determine if non-network alternatives have been duly considered for projects exempt from the RIT-D assessment process.	Noted. As above.

Stakeholder	Issue	AEMC Response
Ergon Energy (pp. 9-10), Energex (p. 19), Victorian DNSPs (p. 16), Endeavour Energy (p. 9), Essential Energy (p. 7)	These stakeholders did not consider sufficient justification existed for a separate annual audit report to be published by the AER. These stakeholders considered the results of any audits could be included in the AER's existing quarterly compliance reports. Ergon Energy considered any audit undertaken by the AER should be a consultative process with the DNSP.	Noted. See section 9.3.5 for further discussion on this matter.
Aurora Energy (p. 8), EnerNOC (p. 6)	These stakeholders supported the requirement for the AER to publish an annual report detailing the results of any audits undertaken in the last 12 months.	Noted. As above.
AER (p. 8)	The AER considered the proposal to require the AER to publish a report on audit activities should also be drafted as an option, not an obligation. The AER considered it was not clear why this obligation was necessary given that it was the enforcement body for the NEM and published quarterly compliance reports and investigative reports on its enforcement and compliance activity.	Noted. As above.
Re-application of the RIT-D		
AER (p. 7)	The AER considered it may be appropriate to include further boundaries around requirements to undertake RIT-D assessments. In particular, the AER suggested further thought be given to whether a DNSP should reapply the RIT-D where: 1. a significant period of time has elapsed since completion of original assessment; 2. significant new information (e.g. revised demand forecast) has emerged since completion of original	The draft rule includes a new provision clarifying that, unless otherwise determined by the AER, a RIT-D proponent would be expected to reapply the RIT-D where there has been a material change in circumstances which, in the reasonable opinion of the RIT-D proponent or any other NSP affected by a RIT-D project, means that the preferred option identified in the original RIT-D assessment is no longer the preferred option. In making such a determination, the draft rule also requires the AER to have regard to the credible options (other than

Stakeholder	Issue	AEMC Response
	assessment which indicates need for investment has changed; 3. estimated costs associated with project have significantly increased since completion of the original assessment (e.g. due to town planning or environmental approval considerations). The AER considered that in these circumstances, the original assessment may not identify the most efficient option and it would be reasonable and prudent to require DNSP to reapply the RIT-D.	the preferred option) identified in the final project assessment report and the change in circumstances identified by the RIT-D proponent. See section 9.3.4 for further discussion on this matter.
Energex (p. 18)	Energex suggested that the AEMC and AER consider circumstances which would result in a different scope or cost being incurred on RIT-D completed projects as a consequence of unforeseen/uncontrollable events - for example, events involving community concern and outcomes from jurisdictional and environmental approvals. Energex requested clarity as to whether a DNSP would be required to undertake a new RIT-D in these circumstances.	Noted. As above.
Energex (supplementary submission, p. 3)	Energex noted that the issue of the re-application of the RIT-D was primarily driven by uncertainty around the relationship between conducting a RIT-D and then building an option to address the identified limitation. It considered the AEMC should clarify that the RIT-D: (1) requires the DNSP to identify the preferred option at the time RIT-D is undertaken; and (2) does not require the DNSP to necessarily build the preferred option identified by the RIT-D. In addition, to address the issue of the re-application of the RIT-D in instances where circumstances may change between a RIT-D assessment and commencement of	The RIT-D has been designed as a process to facilitate stakeholder consultation in identifying the most efficient investment option to meet an identified need. The RIT-D is not intended to test the efficiency of a particular proposed investment per se, nor does it require that a particular investment that satisfies the RIT-D be undertaken. Rather, the RIT-D provides a process to consider the benefits of potential investment options relative to alternative investment options. See section 9.3.4 for further discussion on this matter.

Stakeholder	Issue	AEMC Response
	construction, Energex suggested that a clause be added to the effect that a DNSP would not be required to undertake multiple RIT-D assessments in relation to the same network limitations.	
Other		
Energex (p. 12)	Energex suggested that 31 July 2013 would be a more appropriate date for the first cost threshold review as the new rules are unlikely to be finalised until mid-2012. See proposed cl.5.6.5E(b).	The draft rule requires the AER to carry out a RIT-D cost threshold review every three years from the date the rule commences, or shorter for the first review.
ENA (p. 4)	The ENA was concerned that the overall complexity of the proposed RIT-D would introduce unacceptable delays in the provision of infrastructure and become the subject of compliance and enforcement disputes.	Noted. The Commission is satisfied that the RIT-D process as set out in the draft rule successfully achieves the appropriate balance between ensuring projects are subject to a robust and comprehensive project assessment process and ensuring projects are not unduly delayed, and that investment can proceed in a timely manner. See section 9.3 for further discussion on this matter.
Energex (p. 17)	Energex queried whether it was necessary under proposed clause 5.6.6AB(v) to impose a requirement on the AER's distribution determinations. If so, Energex questioned whether this requirement would best be incorporated into Chapter 6.	Noted. The draft rule does not include reference to the AER's distribution determinations in the draft rules for inclusion in Chapter 5. For clarity, this issue is addressed in draft clauses 6.5.6(e)(11) and 6.5.7(e)(11).
AER (pp. 4-6)	The AER expressed concern regarding the highly prescriptive approach to setting out principles underpinning the RIT-D. The AER noted its preference for the rules to set out high level principles regarding the coverage of the RIT-D, with further details on the nature of the test and classes of costs and benefits set out in the RIT-D. However, the AER noted that if prescriptive principles were	The draft rule sets out the principles that the AER must adopt in promulgating the RIT-D. The purpose of this is to ensure that the RIT-D is applied in a consistent manner, thus providing a level of certainty to NSPs in undertaking network investment, while leaving sufficient discretion with the AER to develop the test consistent with its role as the regulator. The Commission is satisfied that the level of prescription provided in the draft rule is appropriate to meet

Stakeholder	Issue	AEMC Response
	considered appropriate, there were several areas where the drafting of the proposed rule could be revised (these areas are considered discretely in other areas of this summary of issues).	both of these objectives.
AER (p. 8)	While the AER recognised that setting civil penalty provisions was beyond scope of the AEMC's role, it noted that the effectiveness of the planning framework may be improved by classifying the obligations as civil penalty provisions. The AER noted that there had been issues with the RIT-T due to the absence of civil penalty provisions resulting in a lack of enforcement tools available to the AER.	Noted. See section 3.3 for further discussion on civil penalty provisions.
Aurora Energy (p. 7)	Aurora Energy noted that it was not supportive of the introduction of the RIT-D as it appeared to be addressing a 'perceived' failure rather than an actual failure. Aurora Energy also considered that the RIT-D would be more administratively onerous than the current Regulatory Test and that changing the rules to allow for preferred non-network solutions would lead to issues of reliability and security of supply.	Noted. See section 9.3 for the Commission's assessment of the RIT-D against the NEO.
EnerNOC (p. 5)	EnerNOC noted that it was optimistic in the efficacy of the RIT-D but considered the NEO itself may not appropriately consider non-network solutions as a long lasting benefit.	Noted.
Dispute resolution process		
Scope of the dispute resolution process		
ENA (p. 20), Ergon Energy (p. 10), AER (p. 9)	These stakeholders supported the dispute resolution process being limited to DNSPs compliance with the rules in relation to application of the RIT-D.	Noted. See section 10.3.1 for further discussion on this matter.

Stakeholder	Issue	AEMC Response
	The ENA considered a compliance only review would reduce administrative burden and cost for DNSPs and the AER and the likelihood of unnecessary delay in the assessment of investment projects.	
Ergon Energy (p. 10), Aurora Energy (p. 8), EnerNOC (p. 6)	These stakeholders supported the proposed scope of parties eligible to raise a dispute. Ergon Energy noted its support was premised on adequate controls being in place to minimise vexatious or frivolous disputes.	Noted. As above.
Endeavour Energy (p. 9), Victorian DNSPs (p .6), Essential Energy (p. 8), Ergon Energy (p. 24), Energex (p. 18), ENA (pp. 20-21)	These stakeholders considered the scope of parties eligible to raise a dispute was too broad and may result in vexatious claims being lodged and projects delayed. Endeavour Energy suggested the scope of parties be limited to those who made a submission during the consultation period. The Victorian DNSPs considered the scope of parties be limited to the connection applicants, AEMO and affected registered participants. Essential Energy suggested the inclusion of 'relevant and substantive interest' provisions to clarify valid concerns. The ENA, Energex and Ergon Energy suggested that, unless the results of the final project assessment report diverged significantly from the draft project assessment report, parties should not be allowed to raise a dispute in relation to any issue that could have been raised during consultation of the draft project assessment report.	Noted. The Commission considers the draft rule provides sufficient safeguards to protect against the risk that the dispute resolution process may be used inappropriately by some stakeholders in certain circumstances. In addition, the Commission considers that it is appropriate that any stakeholder who may be impacted by a DNSP's decisions under the RIT-D be provided with the opportunity to raise a compliance issue directly with the AER, without being limited in the circumstances in which it may do so. See section 10.3.1 for further discussion on this matter.

Stakeholder	Issue	AEMC Response
	In addition, Ergon Energy considered that disputes should be disallowed where the party lodging a dispute has not submitted a non-network proposal to the project specification report.	
Ergon Energy (p. 10)	Ergon Energy suggested the AEMC consider imposing a nominal fee payable by parties lodging a dispute, refundable if the AER later determines that the dispute had substance, in an effort to deter vexatious or frivolous disputes that unnecessarily delay required investments.	Noted. As above.
AER (p. 9)	The AER noted that while it was broadly supportive of the classes of parties that could raise a dispute, it considered two aspects of the definition of 'interested party' were not clear, namely the terms: (1) "identifies itself as having"; and (2) "market". The AER suggested amending this clause to remove some ambiguity from current drafting applying to both RIT-T and RIT-D disputes.	Noted. The draft rule clarifies the definition of 'interested party'. See section 10.3.1 for further discussion on this matter.
Exemptions from the dispute resolution process		
Ergon Energy (p. 10), Energex (p. 19), Victorian DNSPs (p. 17), Aurora Energy (p. 9), EnerNOC (p. 6), Essential Energy (p. 8), Endeavour Energy (p. 10)	These stakeholders supported the proposal to allow the AER to grant exemptions from the proposed dispute resolution process. Energex considered the proposal would allow the AER to act in best interests of the market and noted that certain investments may be time sensitive and essential to maintain security of supply. Endeavour Energy suggested inclusion of a clause requiring the AER to consider wider community good in relation to time sensitive projects/projects to address	The Commission considers the circumstances in which the AER may grant an exemption from the dispute resolution process are adequately dealt with in other provisions of the draft rule. In addition, the Commission does not consider it appropriate to require the AER to determine the need for a particular project to proceed. For these reasons, this provision has been omitted from the draft rule. See section 10.3.2 for further discussion on this matter.

Stakeholder	Issue	AEMC Response
	security of supply.	
AER (p. 10)	The AER considered the proposal to allow the AER to grant exemptions from the dispute process was unnecessary and unlikely to improve the proposed dispute resolution process. The AER considered the circumstances in which the AER may grant an exemption were adequately dealt with in other provisions in the proposed rule - for example, urgent and unforeseen investments would be exempt from RIT-D and the AER would have the power to dismiss disputes if misconceived or lacking in substance.	Noted. As above.
ENA (p. 21), Ergon Energy (p. 10), Energex (p. 19), Victorian DNSPs (p. 17), Aurora Energy (p. 9), Endeavour Energy (p. 10)	These stakeholders supported the development of specification around the process for applying to the AER for an exemption from the dispute resolution process. Ergon Energy noted support for the development of standard form templates and criteria to streamline the application and approval process for exemptions to the dispute resolution process. Energex considered the process and grounds for providing an exemption should be provided in the rules and suggested this may require a new clause be inserted. The Victorian DNSPs considered the inclusion of reasonable timeframes for the AER's consideration and determination of an application for an exemption would be helpful.	Noted. No longer relevant due to policy amendments.
Other		
Ergon Energy (p. 24)	Ergon Energy questioned whether proposed clause 5.6.6AC(c) should be amended to take into account	Noted. The draft clause takes into account circumstances where a final project assessment report is published in a

Stakeholder	Issue	AEMC Response
	circumstances where a final project assessment report is published in a DAPR.	DAPR.
Energex (p. 20)	Energex considered that proposed clause 5.6.6AC(f)(3) was ambiguous. It suggested that, to avoid delay, any time extension should be limited to the time in which the relevant party would 'reasonably be required' to provide the relevant information.	This aspect of the draft rule has been re-drafted to clarify that where: • the AER makes a request for additional information at least seven days prior to the expiry of the relevant period; and • the RIT-D proponent or the disputing party provides the additional information within 14 days of receipt of the request for information from the AER, the period of time provided for the AER to reject a dispute, or issue a determination on a dispute, will be automatically extended by the time it takes the relevant party to provide the additional information.
Energex (p. 19)	Energex suggested proposed clause 5.6.6AC(c)(1) be amended such that, in addition to setting out grounds of a dispute, a dispute notice must also identify which specific paragraphs of the rules were the subject of the dispute.	Noted. The draft rule requires a disputing party to set out in writing in the dispute notice, the grounds for the dispute. On the basis that the dispute resolution process is limited to DNSPs compliance with the rules, presumably the grounds for dispute would need to include the part of the rules which is subject to dispute. In addition, the Commission notes that the draft rule requires that the AER provide guidance in the RIT-D application guidelines on how disputes will be addressed and resolved. Suggestions in relation to the information to be included in a dispute notice would be better raised and considered in the context of the AER's development of the RIT-D application guidelines.

Stakeholder	Issue	AEMC Response
ENA (p. 20-21), Energex (p. 19)	The ENA and Energex suggested that the AER set out guidelines and a framework to be followed by parties wishing to raise a dispute. These stakeholders considered this would help to clarify what was being disputed and help to ensure disputes were resolved in a timely manner.	Noted. See second point above.
Ergon Energy (p. 24)	Ergon Energy requested clarification in the rules as to what would constitute a 'manifest error' under proposed clause 5.6.6AC(g).	Noted. No longer relevant due to drafting changes.
Implementation and transition		
Duplication of state and national arrangements		
ENA (pp. 3, 5), Ergon Energy (p. 4), Energex (p. 20), Victorian DNSPs (pp. 17 ,6, 7), Endeavour Energy (p. 10)	These stakeholders expressed concern in respect of the potential for duplication of network planning and expansion requirements at both a national and state/territory level. Ergon Energy noted consideration should be given to DNSPs' existing jurisdictional obligations which will need to transition to the new framework. The ENA considered that to achieve the objective of national consistency, a clear commitment should be made to remove jurisdictional requirements when national framework is introduced. Energex was of the view that the transition to the new framework may be a difficult process to achieve as jurisdictional regulatory instruments take considerable time to amend. It considered this issue needed to be taken into consideration and provided for by the transitional provisions in the rules.	It is intended that the existing jurisdictional arrangements for annual planning, annual reporting and project assessment (to the extent that they are covered by the new national framework) will be rolled back to coincide with the introduction of the national framework (where a final rule to this effect is made). The Commission understands that jurisdictions have commenced the process of reviewing and preparing to roll back any state/territory based planning arrangements which are likely to be duplicated by the new distribution planning and expansion framework proposed for inclusion in the NER. The AEMC will continue to keep jurisdiction informed on the progress of the rule change process and the details of the rule to be implemented to enable jurisdictions to undertake the necessary amendments. See section 11.3.1 for further discussion on this matter.

Stakeholder	Issue	AEMC Response
	The Victorian DNSPs considered the AEMC needed to work with jurisdictions to agree to a timetable of implementation and ensure roll-back of the jurisdictional frameworks is coordinated.	
Transition to the national framework		
Aurora Energy (p. 10), Endeavour Energy (p. 10), Victorian DNSPs, (p. 6), ENA (p. 5)	Aurora Energy was concerned that the proposed timeframe for implementation of the national framework was not appropriate for all jurisdictions. Aurora Energy suggested that jurisdictions are best placed to advise the AEMC on transition planning. Endeavour Energy requested further discussion on the timeframes for implementation of the national framework. It considered the timeframes should incorporate some flexibility. Essential Energy considered the proposed transition timeframes would create significant challenges for NSW DNSPs, particularly as each business is currently preparing their regulatory proposal due for lodgement in May 2013. Considered a more appropriate commencement for NSW DNSPs would be mid-2014. The Victorian DNSPs considered the timetable for transition to the national framework was challenging but achievable. These stakeholders supported the proposed nine months for preparation of the first DAPR and the proposed transitional period of 12 months for the RIT-D. They also noted that the rule should include 12 month transitional period for RIT-T for joint investments. The ENA noted that some DNSPs did not have systems in	Noted. See section 11.3.3 for further discussion on these matters.

Stakeholder	Issue	AEMC Response
	place to produce some of the information required in the DAPR. It suggested that the AEMC consider this in relation to allowing a transition period for DNSPs to put in place the required new systems.	
AER (p. 6)	The AER noted that the proposed rule does not include a date for the publication of the RIT-D and application guidelines. It considered that 12 months following the commencement of the rules would be an appropriate period. This would be consistent with the approach adopted for the RIT-T.	The draft rule provides the AER with a period of nine months from the commencement of a rule (where a final rule is made) to prepare and publish the RIT-D and the RIT-D application guidelines. While this period is less than the 12 month period provided in the proposed rule, the Commission notes that it expects there to be a period of a several months between publication of the final rule determination and commencement of a rule which could also be used by the AER to commence preparation of the RIT-D and guidelines if additional time is needed. See section 11.3.3 for further discussion on this matter.
ENA (p. 22), Energex (p. 21), Essential Energy (p. 9), Endeavour Energy (p. 10)	These stakeholders were concerned that the proposed rule did not provide guidance regarding the stage at which a DNSP would be required to comply with the RIT-D in relation to projects that had commenced under the regulatory test. They suggested that any project assessment not complete at the date of the relevant amendment to the RIT-D and/or the application guidelines, should continue and be completed under the regulatory test.	The draft rule requires DNSPs to submit to the AER, by 31 December 2013, a list of projects which have commenced assessment under the regulatory test. Subject to approval by the AER, these projects would then be exempt from consideration under the RIT-D project assessment process (but would continue assessment under the regulatory test). The Commission considers that this approach will provide an effective and efficient means of transitioning to the new RIT-D rules. See section 11.3.4 for further discussion on this matter.
ENA (supplementary submission, pp. 1-2), Energex (supplementary	With regards to the transition from the Regulatory Test to the RIT-D, these stakeholders considered the draft rules	Noted. As above.

Stakeholder	Issue	AEMC Response
submission, p. 4)	should provide for the identification (at the time of the final determination) of proposed projects which have commenced data analysis under the regulatory test. The draft rules or an AER direction under the rules, could then require each DNSP to provide a list of identified limitations to the AER.	
Victorian DNSPs (supplementary submission, p. 2)	The Victorian DNSPs proposed that, for projects which met the RIT-D threshold and were not urgent and unforeseen, a transitional exemption from the new planning framework should be applied to: (1) projects which have completed the regulatory test under clause 5.6.5A of the NER; or (2) projects which have begun the regulatory test within 12 months of the commencement of the RIT-D.	Noted. As above.
ENA (p. 22), Energex (p. 20), Ergon Energy (pp. 4, 17), Endeavour Energy (p. 11), ENA (supplementary submission, p. 2), Energex (supplementary submission, p. 4)	These stakeholders noted that while the proposed rule provided the AER with 12 months to publish the RIT-D and RIT-D application guidelines, it did not specify a timeframe after the release of the test and application guidelines within which DNSPs would be required to comply. The ENA and Energex considered a six month transitional period was necessary. Ergon Energy considered a transitional period of at least 12 months was required in order to provide DNSPs with sufficient time to understand the new regulatory requirements and to adapt processes, procedures, documentation and IS. Endeavour Energy requested time be provided to allow DNSPs to train and prepare staff for the commencement of the rule, to ensure compliance once operational.	The draft rule provides a minimum period of three months between publication by the AER of the RIT-D and the RIT-D application guidelines, and formal commencement of the RIT-D. This period will provide DNSPs with time to complete the necessary preparations to ensure readiness for commencement of the RIT-D. The Commission considers this period is appropriate on the basis that DNSPs would be expected to have commenced preparations for transition to the RIT-D before publication of the RIT-D and associated guidelines by the AER. At the least, the Commission considers that publication of the draft RIT-D and associated guidelines by the AER would provide DNSPs with sufficient information to understand the new regulatory requirements, and hence to begin the necessary preparations.

Stakeholder	Issue	AEMC Response
Other		
ENA (pp. 22-13), Ergon Energy (p. 11), Energex (p. 21), Victorian DNSPs (p. 17), Endeavour Energy (p. 11), Essential Energy (p. 9)	These stakeholders did not expect there to be any implications in not aligning the proposed introduction of the rule with the commencement of NECF. Ergon Energy noted that NECF was a major regulatory change and considered that concurrent implementation of this rule change would place significant pressure on existing change programs and endanger compliant delivery of both programs. The Victorian DNSPs noted that this rule change should not be rushed to align with the start of NECF. This view was supported by the ENA who expressed concern that an expedited rule change process would impact on Commission's ability to meaningfully consider submissions.	Noted.
Other issues		
ETSA Utilities (p. 5), Energex (p. 12)	ETSA Utilities suggested that DNSPs should only be required to notify those parties who register with the DNSP through the demand side engagement register together with the AER and AEMO when publishing relevant documents. ETSA Utilities submitted that the list of registered participants, connection applicants, intending participants etc. is constantly changing and too exhaustive. It considered the burden of maintaining the list may be costly. In relation to the definition of 'interested party' in proposed cl.5.6.6AB(b) and (o), Energex considered it unclear how a DNSP or TNSP could be expected to be aware of which parties were 'interested parties', given the Chapter 10	The Commission notes these concerns and agrees that there are instances in the proposed rule where several requirements to 'notify', 'consult with' or 'request submissions from' certain listed parties would likely prove problematic. For this reason, the Commission has amended several clauses to ensure that the obligations on DNSPs in respect of stakeholder engagement are practical and workable. For example, the requirement in proposed clause 5.6.6AB(o) on DNSPs to "seek submissions from" registered participants, AEMO, non-network providers, interested parties and parties on the demand side engagement register has been amended to require DNSPs to "publish a

Stakeholder	Issue	AEMC Response
	definition. Energex considered this was important as these clauses would require interested parties to be consulted.	request for submissions" from these parties.
Origin Energy (p. 1)	Origin Energy considered the rule change should be mindful of ERC0134 (economic regulation of NSPs).	Noted.
TEC (p. 3)	The TEC suggested the proposed rules should go further in requiring the consideration of demand side participation in light of the supply-side bias in the NEM current rules.	Noted. The draft rule provides a national framework for distribution network planning and expansion which avoids creating bias towards any particular technology, including towards network solutions where non-network options (including embedded generation, energy efficiency and conservation measures) are available. Further, the AEMC is currently reviewing all arrangements that impact on the electricity market supply chain (including the national electricity rules, other national and jurisdictional regulations, commercial arrangements and market behaviours) as part of its Power of Choice review. This review aims to assess the potential for greater demand side participation in the electricity market and identify specific market conditions required for efficient demand side participation. Further information on the review can be found on the AEMC website.[470]
Energex (cover letter), Ergon Energy (cover letter), ENA (cover letter), ETSA Utilities (p. 8)	These stakeholders requested the AEMC hold further discussions, potential through a forum or workshop, with stakeholders either prior to or following the draft determination, to discuss concerns raised in submissions.	Noted.
ENA (p. 3)	The ENA considered the differences between transmission and distribution highlighted the importance of establishing a framework tailored to the requirements of DNSPs and the	Noted.

470 See: www.aemc.gov.au.

Stakeholder	Issue	AEMC Response
	proponents of distribution non-network alternatives. The ENA did not consider that a suitable distribution framework could be established in circumstances where the underlying premise was alignment of the transmission and distribution frameworks.	
Treatment of dual function assets		
Endeavour Energy (pp. 1-2)	Endeavour Energy considered the proposed rule was not clear in respect of the treatment of dual function assets. It recommended that the rule clearly articulate that dual function assets are to be treated as distribution assets for the purposes of planning and expansion under the rules.	The draft rule does not change the current approach to the treatment of dual function assets in the context of network planning and expansion. However, this approach has been clarified by removing any ambiguity and providing for a more integrated approach, where possible, for NSPs that hold obligations both as owners of distribution assets and dual function assets. See section 5.3.2 and section 8.3.4 for a discussion on the treatment of dual function assets within the draft rule.
Ausgrid (p. 4)	Ausgrid did not consider that DNSPs should not have to prepare a DAPR as well as a transmission APR. Ausgrid considered that its activities in relation to planning and operating both distribution assets and dual function assets should be covered by one report.	It is not the intention for DNSPs with dual function assets to face duplicate planning and reporting obligations as a consequence of being a DNSP for the purposes of their distribution assets and a TNSP for the purposes of their dual function assets. For this reason, the draft rule clarifies that DNSPs may produce one comprehensive annual planning report covering all their network assets. See section 5.3.2 for further discussion on this matter.
Ausgrid (p. 5)	Ausgrid noted that the provisions regarding joint network investment require clarification on the AEMC's policy intent regarding the treatment of these investments. It noted that this issue was of particular concern to Ausgrid given it is both a TNSP and DNSP for the purpose of Chapter 5,	Noted. See section 8.3.4 for further discussion on the treatment of dual function assets in the context of joint planning.

Stakeholder	Issue	AEMC Response
	owns and operates dual function assets and undertakes detailed joint planning both internally as TNSP and DNSP, and as a TNSP and DNSP with Transgrid.	

B Summary of legal issues raised in submissions

The table below provides a summary of the legal issues raised by stakeholders in their submissions and supplementary submissions to the consultation paper.[471] The table, ordered by component of the national framework, sets out the Commission's response to each issue.

For ease of reference, relevant page numbers have been included in the table.

The submissions and supplementary submissions received are available on the AEMC website at www.aemc.gov.au.

Proposed rule clause	Stakeholder	Issue	AEMC Response
5.6.2 Network Development			
5.6.2(e)	Energex (p. 6)	"The relationship between the process set out in clause 5.6.2(e) and the joint planning process under clauses 5.6.2AA(g)-(j) is not clear. ENERGEX queries whether clause 5.6.2(e) is still intended to apply to DNSPs given the introduction of this new process."	This obligation will continue to apply to DNSPs (draft clause 5.11.2). It operates alongside the joint planning obligation in draft rule 5.14 and imposes obligations to notify registered participants of limitations and the proposed course of action to undertake corrective action.
5.6.2(e)(2)	Endeavour Energy (p. 9)	"It is not clear from the rules whether separate STT/Project assessment documents need to be lodged regarding each network limitation. Endeavour Energy believes that the requirements under clause 5.6.2(e)(2) should be rolled into the requirements to publish an annual planning statement which essentially does the same thing and/or Project Specification stage (see clause 5.6.6AB(g) - requirement to consult on identified need in Project Specification Requirement) which is filtered by the relevant thresholds."	Noted. As above, the RIT-D needs to be applied to a project to address an identified need. Draft clause 5.11.2 relates to the notification of limitations and the timeframes for corrective action to address those limitations. It is also noted that investments of the kind contemplated in this clause are not specifically excluded from the RIT-D as some joint planning projects may be assessed under the RIT-D.

471 Appendix A provides a summary of the policy issues raised by stakeholders in their submissions and supplementary submissions to the consultation paper.

Proposed rule clause	Stakeholder	Issue	AEMC Response
5.6.2(e)(3)	Ausgrid (p. 10)	"Notification in 5.6.2 (e)(3) only arises from the forecasts of Registered Participants. However, the analysis of Registered Participant forecasts does not make much sense in a distribution context as there are few Registered Participants and they have little impact on the system performance. Moreover, this clause is referred to extensively in 5.6.5C and 5.6.5CB when considering exclusion from RIT-T and RIT-D. However, it would not make sense to exclude an investment from either the RIT-D or RIT-T because of limitations arising from Registered Participant forecasts. Ausgrid would contend that it would make more sense to require NSPs to develop forecasts, taking into account forecasts provided by Registered Participants. AEMC should consider a revision to that effect."	See comment for clause 5.6.2(e) above. It is noted that investments of the kind contemplated in this clause are not specifically excluded from the RIT-D as some joint planning projects may be assessed under the RIT-D.
5.6.2(k)(1)	Ausgrid (p. 10)	"Provides for inclusion of option costs in TUOS but it is not clear what option is referred to as the clause does not link with any previous clauses. Ausgrid suggests that the need for this clause be revisited in light of the current Chapters 6 and 6A."	This clause has been omitted from the draft rule.
5.6.2AA Distribution Annual Planning Review and Report			
General			
5.6.2AA	Energex (p. 22)	"ENERGEX notes that there are a number of typographical errors, including: • defined terms that are incorrectly referred to ('Customer transmission use of system charges' in cl.5.6.2AA(l)(12)); and 'Embedded Generators' in	Noted. The relevant amendments have been made. See draft schedule 5.9(h) and (i) and draft clause 5.10.2 (local definitions).

Proposed rule clause	Stakeholder	Issue	AEMC Response
		cl.5.6.2AA(d)(13)); • the definition of 'transmission-distribution connection point' should refer to the agreed point of supply established between 'a transmission system and a distribution system'."	
Purpose			
5.6.2AA(a)(4)	Ergon Energy (p. 12)	"Ergon Energy does not support the use of the colloquial term 'level playing field' and recommends amending this to: "(4) ensure equitable treatment for all regions in terms of attracting investment and promoting efficient decisions"."	The purpose clause set out in proposed clause 5.6.2AA(a) has been omitted from the draft rule.
Scope of the distribution annual planning review			
5.6.2AA(f)	Ausgrid (p. 10)	"The term 'activities' does not make sense from a planning perspective and should be removed."	Noted. The relevant amendment has been made. See draft clause 5.13.2(c).
Requirements of the Distribution Annual Planning Review			
5.6.2AA(h)	Energex (pp. 5-6)	"ENERGEX believes that clause 5.6.2AA(h) requires greater drafting clarity and suggests the following amendments: • clause 5.6.2AA(h) should be amended to read 'Transmission Network Service Provider the transmission network of which is connected to the Distribution Network Service Provider's network'; • the provisions regarding joint planning in respect of a declared shared network of an adoptive jurisdiction	Noted. The joint planning requirements are now articulated in draft clause 5.14.1.

Proposed rule clause	Stakeholder	Issue	AEMC Response
		should be inserted at the end of paragraph (h); and • clause 5.6.2AA(h)(4)(ii) and (iii) also need to be recast to be consistent with the 'must' before the colon in the opening words of clause 5.6.2AA(h)."	
5.6.2AA(h)(3)	Victorian DNSPs (p. 8)	"The inclusion of "any interested party that has informed AEMO of its interest in the relevant plans" as a party to joint network planning has the potential to significantly increase the time and resources involved in conducting joint planning. This provision would apply only in Victoria, so its inclusion is at odds with the AEMC's stated criterion of "harmonisation of jurisdictional requirements". The rationale for this provision is unclear. It is highly doubtful whether such a provision would contribute to the achievement of the National Electricity Objective. The provision should be removed."	The Commission considers that the inclusion of the term 'interested party' in this clause warrants further consideration and would welcome submissions on this matter.
5.6.2AA(h)(4)	Ausgrid (p. 10)	"5.6.2AA(h)(4)(ii) refers to applying the RIT-T to the "identified need". The definition of "identified need" refers to the reason why the NSP proposes to undertake a particular investment. It is not apparent how this is susceptible to the application of the RIT-T. Ausgrid suggests that it would be more appropriate to state that the regulatory investment test for transmission must be carried out where the system limitation is proposed to be addressed by a joint network investment."	The RIT-T now applies to 'RIT-T projects' which include joint planning projects in most cases. See the definition of 'RIT-T project' in draft clause 5.10.2.
5.6.2AA(j)	Energex (p. 6)	"ENERGEX suggests that this clause is unnecessarily complicated, and to provide greater clarity it should simply require a Distribution Network Service Provider to engage with non-network providers, and consider non-network alternatives, in accordance with the provider's Demand	The key demand side engagement obligations are now set out in draft clauses 5.13.2(e) to (j).

Proposed rule clause	Stakeholder	Issue	AEMC Response
		Side Engagement Strategy."	
Demand Side Engagement Strategy			
5.6.2AA(l)	ENA (p. 6)	"Clause 5.6.2AA(l) requires DNSPs to 'prepare and make available' a Demand Side Engagement Document. The ENA suggests that clause 5.6.2AA(l) should be amended to read similar to clause 5.6.2AA(m) and require DNSPs to 'prepare and publish' the document as 'make available' is not defined under the Rules and may be open to different interpretations."	Agreed. See draft clause 5.13.2(g).
5.6.2AA(l)	Energex (p. 2)	"Clause 5.6.2AA(l) requires DNSPs to prepare and make available a Demand Side Engagement document. ENERGEX suggests that the phrase 'make available' should be amended to 'publish'. 'Make available' is not defined under the Rules and is therefore subject to different interpretations."	As above.
5.6.2AA(l)(15)	Ergon Energy (p. 13)	"Ergon Energy suggests replacing 'a' embedded generation with 'an'. That is: "(15) the process for lodging an embedded generation connection application and the factors taken into account by the Distribution Network Service Provider when assessing connection applications.""	Noted. See draft schedule 5.9(k).
5.6.2AA(p)	ENA (p. 6)	"The ENA also suggests that the following amendment to clause 5.6.2AA(p) would help clarity when the Demand Side Engagement Register would be required to take effect: Each Distribution Network Service provider must, from the date on which its first Demand Side Engagement document must be published under paragraph (m), establish and maintain a register (Demand Side	Noted. See draft clause 5.13.2(j).

Proposed rule clause	Stakeholder	Issue	AEMC Response
		Engagement Register) for those parties wishing to be advised of relevant developments relating to clause 5.6.2AA and clause 5.6.5CA."	
5.6.2AA(p)	Energex (p. 2)	"ENERGEX suggests that the following amendment to clause 5.6.2AA(p) would provide clarity in relation to when the Demand Side Engagement Register would be required to take effect: Each Distribution network Service provider must, from the date on which its first Demand Side Engagement document must be published under paragraph (m), establish and maintain a register (Demand Side Engagement Register) for those parties wishing to be advised of relevant developments relating to clause 5.6.2AA and clause 5.6.5CA."	As above.
Distribution Annual Planning Report			
5.6.2AA(q)	Energex (p. 4)	"ENERGEX notes that this clause makes reference to the term 'jurisdiction specified date', which is defined under Chapter 10. ENERGEX suggests that this definition is not required to be capitalised under Chapter 10 and should include an undefined reference to 'local regulation'."	See the approach to the date for publication of the Distribution Annual Planning Report made under draft clause 5.13.2.
Contents of the Annual Planning Report			
5.6.2AA(t)	Victorian DNSPs (p. 10)	"Clause 5.6.2AA(t), which is referenced in the definition, specifies the distribution annual reporting requirements. The definition of "joint network investment" would be improved if a more suitable, clearer cross-reference were included. For the avoidance of doubt, it would be preferable that the definition states explicitly that "joint network investment" includes all transmission-to-distribution connection assets. Moreover,	The definition of 'joint network investment' is not included in the draft rule. See the definition of 'joint planning project' in draft clause 5.10.2 (local definitions). See also draft clause 5.13.2(d) in relation to transmission - distribution connections points.

Proposed rule clause	Stakeholder	Issue	AEMC Response
		the term contains the word “network”, which is defined in the NER to explicitly exclude connection assets. The proposed definition is therefore a source of potential confusion because the intention is to include connection assets in the definition of joint network investment. It would be preferable to delete the work “network” and to adopt the term “joint investment”."	
5.6.2AA(u) and (w)	Ergon Energy (p. 12)	"Ergon Energy recommends italicising ‘AER’ as it is a defined term in Chapter 10 of the Rules. That is: “A Distribution Network Service Provider may apply to the AER for an exemption from or variations to any requirement of clause S5.8” and “The AER must…”."	Noted. Proposed clauses 5.6.2AA (u) and (w) have been omitted from the draft rule.
Schedule 5.8 Distribution Annual Reporting Requirements			
S5.8.2(1)	Energex (p. 4)	"ENERGEX notes and suggests the following minor amendments: Substitute ‘met’ for ‘provided’."	Noted. The relevant amendments have been made. See the introduction of draft schedule 5.8.
S5.8.2(2)(ii)	Ausgrid (p. 12)	'The term ‘transmission-distribution connection points” is not referred to in the clause 5.6.2AA(g)(1) forecast requirements. The draft Rules also omit forecasts for sub-transmission substations. It is therefore assumed that transmission-distribution connection points are intended to describe sub-transmission substations. The AEMC should amend as appropriate. With regards to points (E) to (J) – not all of the descriptions are applicable to the items in (A) to (D). For example, power factor at time of peak load (H) is not applicable to lines as it is usually measured at a metering point. Ausgrid contends that there should be a qualification such as “Including for each item specified above (and where applicable)”."	While sub-transmission substations are not specific requirements under draft clause 5.13.1(d), it is noted that there is a general obligation under draft clause 5.13.1(c) for a DNSP's distribution annual planning review to include assets that would be expected to have a material impact of the DNSP's network. Sub-transmission substations may be captured under this clause. It is also noted that draft schedule 5.8(b)(2) contemplates that a broader set of information may be relevant to forecasts.

Proposed rule clause	Stakeholder	Issue	AEMC Response
S5.8.2(4)(v)(A)	Energex (p. 4)	"Clause S5.8.2(4)(v)(A) should cross refer to paragraph (i) (not (ii))."	Noted. See draft schedule 5.8(d)(7)(i).
S5.8.2(4)(v)(c)	Energex (p. 4)	"Clause S5.8.2(4)(v)(c) should end 'to defer the forecast system limitation'."	Noted. See draft schedule 5.8(d)(7)(iii).
S5.8.2(5)(iii)	Energex (p. 4)	"Clause S5.8.2(5)(iii) – delete 'of the investment'."	Noted. See draft schedule S5.8(e)(2).
S5.8.2(5)(iv)	Energex (p. 5)	"It is not clear how clause S5.8.2(5)(iv) can apply to a regulatory investment test for distribution which is only in progress."	Noted. See clarification in draft schedule 5.8(e)(4).
S5.8.2(10)(v)	Energex (p. 5)	"Clause S5.8.2(10)(v) – delete 'a summary of the'."	Noted. See draft schedule 5.8(j)(5).
S5.8.2(14)	Energex (p. 5)	"Clause S5.8.2(14) and the commencement of each of paragraphs (i) – (iv) need to be harmonised ('identifying', 'summarising', 'providing')"	Noted. See draft schedule 5.8(n).
5.6.5B Regulatory investments test for transmission			
Principles			
5.6.5B(c)(9)	Ergon Energy (p. 14)	"The draft amendment incorrectly repeats "Distribution Network Service Provider"."	Noted. See draft clause 5.16.1(c)(9).
5.6.5C Investments subject to the regulatory investments test for transmission			
5.6.5C	Energex (p. 6)	"The blanket substitution of 'TNSP or DNSP' for TNSP in clause 5.6.5C does not sit well with joint network investments carried out by DNSPs, eg. it may result in a DNSP being required to carry out transmission investments under clause 5.6.5C(d). Conversely, clause	Noted. See draft clause 5.16.3. Each reference to TNSP has been considered and replaced with a reference to "RIT-T proponent" where appropriate.

Proposed rule clause	Stakeholder	Issue	AEMC Response
		5.6.5D(b) should extend to DNSPs and joint network investments."	
5.6.5CA Regulatory investments test for distribution			
5.6.5CA(c)(4)(vi)	Energex (p. 8)	"ENERGEX notes that this clause should refer to 'classes of market benefits' not 'classes or market benefits'."	Noted. See draft clause 5.17.1(c)(4)(vi).
5.6.5CA(c)(4)(v)	Ausgrid (p. 11)	"'the potential for load transfer capacity of embedded generating units' should read "capacity of embedded generators to take up load"."	Noted. See draft clause 5.17.1(c)(4)(v).
5.6.5CA(d)	Energex (p. 9)	"ENERGEX suggests that the term 'may' is ambiguous and open to interpretation. It could suggest that the DNSP does not have to consider market benefits at all. ENERGEX suggests that the AEMC amend this clause to provide greater clarity."	The Commission considers that it is clear from draft clause 5.17.1(c)(4) that DNSPs are required to consider market benefits when carrying out the RIT-D. However, the quantification of these benefits is not mandatory.
5.6.5CB Investments subject to the regulatory investment test for distribution			
5.6.5CB(a)(2)	Ausgrid (p. 11)	"Ausgrid submits that the AEMC should clarify the intent of "most expensive option" to recognise that as drafted, it could lead to almost all every distribution investment being subject to the RIT-D. This is also addressed in the ENA submission."	Noted. See draft clause 5.17.3(a)(2).
5.6.5CB(a)(8)	ENA (p. 15)	"The ENA is concerned that the phrase 'as allocated by the distribution network service provider in accordance with the recognised Cost Allocations Methods and any applicable AER guidelines' is ambiguous. The ENA suggests that this phrase should be amended to reflect the current wording of clause 6.15.1 'as allocated by the Distribution Network Service Provider in accordance with	The reference to cost allocation in this clause has been omitted on the basis that it is unnecessary and does not apply in the situation where a TNSP is the lead party for a RIT-D. See draft clause 5.17.3(a)(6).

Proposed rule clause	Stakeholder	Issue	AEMC Response
		the Cost Allocation Method that has been approved in respect of that provider by the AER'."	
5.6.5CB(b)	Ausgrid (p. 11)	"Dual function assets are not distribution investments as they are by definition transmission assets."	Noted. See draft clause 5.17.3(b) regarding application of the RIT-D to dual function assets.
5.6.5CB(c)	Ausgrid (p. 11)	"Clauses 5.6.5C and 5.6.5CB(c) refer to an investment being required to address an urgent and unforeseen network issue that would otherwise put at risk the reliability of the distribution network. On its natural reading this would require the reliability of the whole of the transmission or distribution to be at risk. This may be appropriate for transmission, but it would have very limited utility for a distribution network. It is suggested that the purpose of the clause would be better achieved if it referred to "put at risk the reliability of the distribution/transmission network or a significant part of that network.""	Noted. The relevant amendments have been made. See draft clause 5.17.3(c).
5.6.5D Identification of credible options			
5.6.5D(a)(2)	ENA (p. 17)	"The ENA also notes there appears to be a typographical error in under this clause in that the reference to paragraph (b) should be a reference to paragraph (b1)."	Noted. See draft clause 5.15.2(a).
5.6.5D(b1)(5) and (6)	ENA (p. 17)	"The ENA suggests that both these clauses should not refer to 'credible options' but rather be amended to 'the option' because a DNSP, at this stage in the process, has not yet determined whether the option is credible."	Proposed clauses 5.6.5S(b1)(5) and (6) have been omitted from the draft rule.
5.6.5E Review of cost thresholds			
5.6.5E(a) and (a1)	Energex (p. 11)	"ENERGEX notes that clauses 5.6.5E(a) and 5.6.5E(a1)	Noted. See draft clause 5.15.3(b)(6).

Proposed rule clause	Stakeholder	Issue	AEMC Response
		do not refer to the definitions of terms where a monetary threshold may be varied by a cost threshold determination (eg. see the definition of 'potential transmission project'). ENERGEX seeks further clarity on this point."	
5.6.5E(a1)	Energex (p. 11)	"ENERGEX suggests that minor amendments be made to clause 5.6.5E(a1) as follows: Every 3 years (or shorter for the first review) the AER must undertake a review (cost threshold review) of the changes in the input costs used to calculate the estimated capital costs in relation to investments subject to the regulatory investment test for distribution and the cost threshold for refurbishment, replacement, and urgent and unforeseen investments subject to the Distribution Annual Planning Report, for the purposes of determining whether the amounts of: (1) $5 million referred to in clauses 5.6.5CB(a)(2) and (8); (2) $10 million referred to in clause 5.6.6AB(t)(2); and (3) $20 million referred to in clause 5.6.6AB(y); and (4) $2 million referred to in clause S5.8(7), (each a cost threshold) need to be changed…"	Noted. See draft clause 5.13.2 (note that proposed clause 5.6.5E has been re-structured).
5.6.5E(a1)	Ergon Energy (p. 19)	"This should be amended to: "(1) $5 million referred to in clauses 5.6.5CB(a)(2) and (8)"."	Noted. See draft clause 5.15.3(d).
Project assessment draft report			
5.6.6(j)	Ergon Energy (pp. 19-20)	"Ergon Energy queries whether the AEMC intended this to be: "If the Transmission Network Service Provider or Distribution Network Service Provider (as the case may be) elects to proceed with the proposed transmission investment or joint network investment (as the case may be), within 12 months of the end date of the consultation period referred to in paragraph (h), or such longer time period as is agreed in writing by the AER, the	Noted. See draft clause 5.16.4(j).

Proposed rule clause	Stakeholder	Issue	AEMC Response
		Transmission Network Service Provider or the Distribution Network Service Provider (as the case may be) must prepare a report (the project assessment draft report), having regard to the submissions received, if any, under paragraph (g) and make that report available to all Registered Participants, AEMO and interested parties." "	
Project assessment conclusions report			
5.6.6(t)	Ergon Energy (p. 20)	"Ergon Energy recommends italicising 'AER' as it is a defined term in Chapter 10 of the Rules. That is: "…as is agreed in writing by the AER"."	Noted. See draft clause 5.17.4(u)(2).
5.6.6AA Determination that proposed transmission investment satisfies the regulatory investment test for transmission			
5.6.6AA(e)	Ergon Energy (pp. 20-21)	"Ergon Energy recommends that this should be amended to: "(1) render the Transmission Network Service Provider or Distribution Network Service Provider (as the case may be) an invoice for the reasonable costs; or (2) determine that the reasonable costs should: (i) be shared by all the parties to the dispute, whether in the same proportion or differing proportions; or (ii) be borne by a party or parties to the dispute other than the Transmission Network Service Provider or Distribution Network Service Provider (as the case may be) whether in the same proportion or differing proportions; and (iii) the AER may render invoices accordingly.""	The Commission does not consider this change is necessary (note that existing clause 5.6.6AA(e) does not qualify the costs that might be recovered.
5.6.6AB Regulatory investment test for distribution procedures			
5.6.6AB	ENA (p. 12)	"...the term 'consult' is used throughout the RIT-D and may be subject to different interpretations as to what is actually required by the term. For example, consulting	The Commission does not consider it necessary to be prescriptive regarding the form of consultation under these rules.

Proposed rule clause	Stakeholder	Issue	AEMC Response
		under 5.6.6AB(g) may be different as to what form of consultation is required under clause 5.6.6AB(p) and it may be interpreted differently by DNSPs. This outcome would not be consistent with the principle of seeking consistency across the market participants. The ENA suggests that the term 'consult' should be defined under Chapter 10, particularly to avoid unnecessary disputes."	
5.6.6AB	Energex (p. 15)	"The term 'consult' is used throughout RIT-D and may be subject to different interpretations as to what is actually required by the term. For example, consulting under 5.6.6AB(g) may be different as to what form of consultation is required under clause 5.6.6AB(p) and it may be interpreted differently across DNSPs. This outcome would not be consistent with the principle of seeking consistency across the NEM. ENERGEX suggests that the term 'consult' should be defined under Chapter 10. ENERGEX is concerned that since the classes of disputing parties has been broadened, the lack of clarity behind the term 'consult' has the potential to be the subject of numerous and lengthy disputes."	As above.
5.6.6AB(b) (and (o))	Energex (p. 12)	"Moreover, paragraph (b) should also refer to joint network investments."	Draft clause 5.17.4(a) now refers to RIT-D projects that are subject to the RIT-D under draft clause 5.17.3.
Specification Threshold Test			
5.6.6AB(d)	ENA (p. 18)	"The ENA submits that the term 'proposed' under clause 5.6.6AB(d) and which is used in subsequent clauses (clause 5.6.6AB(m)), creates unnecessary confusion. At this stage of the RIT-D the DNSP has not proposed any	Noted. See draft clauses 5.17.4(b) to (d) and the definition of "potential credible option" in draft clause 5.10.2 (local definitions).

Proposed rule clause	Stakeholder	Issue	AEMC Response
		investment, the DNSP has only identified a need. As such, the phrase 'proposed investment' needs to be reworded to simply state 'investment', and the phrase "proposed distribution investment" to simply state "distribution investment"."	
5.6.6AB(d)	Energex (p. 13)	"ENERGEX submits that the term 'proposed' under clause 5.6.6AB(d) and which is used in subsequent clauses (clause 5.6.6AB(m)), creates unnecessary confusion. At this stage of the RIT-D the DNSP has not proposed any investment, the DNSP has only identified a need. ENERGEX considers that the phrase 'proposed investment' be reworded to simply state 'investment', and the phrase 'proposed distribution investment' to simply state 'distribution investment'."	As above.
5.6.6AB(e)	Ergon Energy (p. 21)	"Ergon Energy recommends inserting commas after 'If' and 'Test'. That is: "If, after undertaking the Specification Threshold Test, the Distribution Network Service Provider determines…"."	Noted. See draft clauses 5.17.4(b) to (d).
Project specification stage			
5.6.6AB(f)	ENA (p. 18)	"The ENA suggests that clause 5.6.6AB(f) is unnecessarily convoluted and should be amended to read as follows: 'A Distribution Network Service Provider must carry out the requirements of paragraphs (g) to (l) where a Specification Threshold Test assessment by the Distribution Network Service Provider determines that there are credible options that are non-network options which can either defer or remove the need for the proposed distribution investment'."	Noted. See draft clauses 5.17.4 (b) to (d) which clarifies when a non-network options report must be prepared.

Proposed rule clause	Stakeholder	Issue	AEMC Response
5.6.6AB(f)	Energex (p. 14)	"ENERGEX suggests that clause 5.6.6AB(f) appears to be unnecessarily convoluted and onerous and may be amended to read as follows: 'A DNSP must carry out the requirements of paragraphs (g) to (l) where a STT assessment by the DNSP determines that there are credible options that are non-network options which can either defer or remove the need for the proposed distribution investment'."	As above.
5.6.6AB(g) and (h)	Energex (p. 14)	"ENERGEX is concerned that clause 5.6.6AB(g) only requires the DNSP to consult on the identified need, however 5.6.6AB(h) extends the consultation to options. ENERGEX notes that the term 'options' in 5.6.6AB(h)(6) is undefined and should be amended to 'credible options'. Such an amendment would make it consistent with the wording adopted in the AEMC's Appendix A flowchart. ENERGEX therefore submits that (g) be amended to state 'A DNSP will be required to consult on the identified need and credible options as set out in (h)-(l)', and the term 'options'/'investment options' be changed to 'credible options' in (h). This wording would more accurately reflect what appears to be the intention of this clause."	Proposed clause 5.6.6AB (g) has been omitted from the draft rule.
Draft project assessment report			
5.6.6.AB(m)	Ausgrid (p. 12)	"It is not clear from the structure of this clause from when the 12 month period referred to in subclause (1) runs. The intention appears to be that it should run from the end of consultation on a project specification report or the publication of a STT, but this is not clear and should be amended."	Noted. Draft clause 5.17.4(i) clarifies the relevant time periods.

Proposed rule clause	Stakeholder	Issue	AEMC Response
5.6.6AB(n)(5)	Ergon Energy (p. 23)	"Ergon Energy recommends that this be changed to: “(5) where relevant and available, a quantification of each applicable market benefit for each credible option”. This ensures consistency with clause 5.6.5CA(d) which provides DNSPs the option, not obligation, to quantify market benefits."	The commission does not consider the words "and available" are required. See draft clause 5.17.4(j)(5).
5.6.6AB(q) and (r)	Ergon Energy (p. 23)	"Ergon Energy questions the inconsistency and logic behind the use of two different time measurements (i.e. ‘business days’ versus ‘weeks’)."	See draft clause 5.17.4(m) and use of the term "six weeks". Proposed clause 5.6.6AB(r) has been omitted from the draft rule.
5.6.6AB(s)	Energex (p. 16)	"ENERGEX is concerned why the phrase ‘proposed distribution investment’ is used in this clause. ENERGEX suggests a more accurate phrase would be ‘proposed preferred option’. At this stage the DNSP has already identified a preferred option (as per the wording clause 5.6.6AB(n)(10))."	Proposed clause 5.6.6AB(s) has been omitted from the draft rule.
Exemption from draft project assessment report			
5.6.6AB(t)(1)	Energex (p. 13)	"ENERGEX suggests that the appropriateness and scope of the term ‘material’ in (t)(1) needs to be amended because the STT does not put a materiality threshold on the options. This appears to be an internal inconsistency in the draft Rules."	See draft clause 5.17.4(n) which links the exemption from the requirement to prepare a draft project assessment report to a determination under draft clause 5.17.4(d).
Final project assessment report			
5.6.6AB(x)	ENA (p. 19)	"The ENA believes that clause 5.6.6AB(x) is ambiguous as it does not appear to contemplate the requirement to publish a FPAR after fast tracking RIT-D through the DPAR exemption under clause 5.6.6AB(t). This means the requirement to set out matters detailed in the DPAR and	Noted. The relevant amendments have been made. See draft clause 5.17.4(r).

Proposed rule clause	Stakeholder	Issue	AEMC Response
		summarise submissions on the DPAR is impossible, if a DPAR was never required to be published. The ENA suggests a clause be drafted that states: (1) A Distribution Network Service Provider is not required to comply with (x) if the Distribution Network Service Provider is exempt from publishing a draft project assessment report under paragraph (t)."	
5.6.6AB(x)	Ergon Energy (pp. 23-24)	"Ergon Energy recommends that this should be amended to: “Where available, the final project assessment report must set out…” as this information will only be available if a draft project assessment report was prepared."	As above.
5.6.6AB(z)	Ausgrid (p. 12)	"As the RIT-D applies to other than distribution assets, (dual function assets and transmission assets for distribution needs) this needs to be more general and should be worded to cover NSP not DNSP."	Proposed clause 5.6.6AB(2) has been omitted from the draft rule.
5.6.6AC Disputes in relation to application of regulatory investment test for distribution			
5.6.6AC(b)	Victorian DNSPs (p. 12)	"This provision should be redrafted along the following lines: A dispute under this clause 5.6.6AC may only be raised on the grounds that: (1) the Distribution Network Service Provider has not correctly applied the regulatory investment test for distribution in accordance with the Rules; or (2) there was a manifest error in the calculations performed by the Distribution Network Service Provider in applying the regulatory investment test for distribution.	Noted. See draft clauses 5.17.5(a) and (b).

Proposed rule clause	Stakeholder	Issue	AEMC Response
		A dispute cannot be raised in relation to any matters set out in the final project assessment report which: (3) are treated as externalities by the regulatory investment test for distribution; or (4) relate to an individual's personal detriment or property rights."	
5.6.6AC(d)(3)	Energex (p. 18)	"ENERGEX suggests that clause 5.6.6AC(d)(3) be amended to also cross reference paragraph (g)."	This drafting change is not considered necessary as the grounds for a dispute are set out in draft clause 5.17.5(a).
5.6.6AC(j)	Energex (p. 20)	"ENERGEX is concerned that clause 5.6.6AC(j) does not appear to be a provision that permits the AER to grant an exemption from the dispute resolution process in the first place and upon which this clause can therefore operate."	Proposed clause 5.6.6AC(j) has been omitted from the draft rule.
5.6.6AC(j)	Victorian DNSPs (p. 12)	"The Businesses support this provision, although it would benefit from the following clarification at the commencement of the clause: "For a particular distribution investment, a DNSP may apply to the AER for an exemption to the RIT-D dispute resolution process." The inclusion of reasonable timeframes for the AER's consideration and determination of an application for exemption would also be helpful."	As above.
Chapter 10 Definitions			
'considered project'	Energex (p. 22)	"ENERGEX suggests that the Chapter 10 definition of 'considered project' (paragraph (3)(iii)) be amended to insert 'or joint network investment' after 'transmission investment' and delete 'distribution' before 'transmission'."	Noted. See the definition of 'considered project' in draft clause 5.10.2 (local definitions).

Proposed rule clause	Stakeholder	Issue	AEMC Response
'considered project'	Ergon Energy (p. 25)	"The draft amendment incorrectly inserts 'distribution' within the term 'regulatory investment test for transmission'."	As above.
'Demand Side Engagement Register'	ENA (p. 6)	"The ENA queries the definition of Demand Side Engagement Register in Chapter 10 as it does not make any reference to the Register and is therefore incomplete."	Noted. See the definition of 'demand side engagement register' in draft clause 5.10.2 (local definitions).
'Demand Side Engagement Register'	Ergon Energy (p. 25)	"The Demand Side Engagement Register is not referenced in clause 5.6.2AA(k) and Ergon Energy queries whether it is appropriate to rely on this clause as the correct definition."	As above.
'Demand Side Engagement Register'	Energex (p. 2)	"ENERGEX questions whether it is appropriate for the Chapter 10 definition of 'Demand Side Engagement Register' to refer and rely on clause 5.6.2AA(k). ENERGEX suggests that this is not a true definition of the Register and makes no reference to the Register."	As above.
'disputing party'	Energex (p. 19)	"ENERGEX also suggests that the definition of disputing party requires amendment as the cross reference should be to cl.5.6.6AC(c) and not cl.5.6.6AC(c)(1)."	Noted. See definition of 'disputing party' in draft clause 5.10.2 (local definitions).
'firm delivery capacity'	Energex (p. 22)	"ENERGEX suggests that under the Chapter 10 definition of 'firm delivery capacity' definition, the reference to equipment should be deleted (see the definition of 'total capacity') and 'having regard to' should be substituted for 'giving consideration to'."	Noted. See definition of 'firm delivery capacity' in draft clause 5.10.2 (local definitions).
'interested party'	Energex (p. 20)	"Under paragraphs (a) and (b) in Chapter 10's definition of the phrase 'interested party', ENERGEX suggests that reference should be made to joint network investments as	Noted. For the definition of 'interested party', see draft clause 5.15.1 and Chapter 10 (definitions).

Proposed rule clause	Stakeholder	Issue	AEMC Response
		well as to transmission and distribution investments."	
'joint network investment'	Ergon Energy (p. 25)	"This definition incorrectly references 5.6.2AA(t) which relates to the contents of the DAPR. This should be amended to: “An investment identified under clause 5.6.2AA(h) which affects…”."	Noted. See the definition of 'joint planning project' in draft clause 5.10.2 (local definitions).
'joint network investment'	Energex (p. 6)	"The reference in the definition of ‘joint network investment’ to clause 5.6.2AA(t) appears to be an error. ENERGEX suggests that it should instead refer to clause 5.6.2AA(h)."	As above.
'normal cyclic rating'	Energex (p. 5)	"ENERGEX suggests that the phrase ‘giving consideration to’ be amended to ‘having regard to’."	Noted. See definition of 'normal cyclic rating' in draft clause 5.10.2 (local definitions).
‘sub-transmission’, ‘sub-transmission line’, and ‘zone substation’	Energex (p. 5)	"The reference to zone substations in the definitions of ‘primary distribution feeder’ and ‘sub-transmission line’ should instead be included in the definition of ‘sub-transmission’."	Noted. See definition of 'sub-transmission' in draft clause 5.10.2 (local definitions).
'sub-transmission'	Victorian DNSPs (p. 13)	"Under this definition, transmission-to-distribution connection assets would be classified as sub-transmission assets. This would be inconsistent with current practice. We consider that the definition should exclude transmission-to-distribution connection assets."	As above.
'System limitation'	Ergon Energy (p. 25)	"This should be amended to: “Has the meaning given in clause 5.6.2AA(g)(2)”."	Noted. See the definition of 'system limitation' in draft clause 5.10.2 (local definitions).
Other			
General	Ergon Energy (pp. 25-26)	"To ensure consistency throughout the Rules, Ergon Energy suggests inserting ‘the’, where appropriate, before	Noted. Relevant amendments have been made, where appropriate.

Proposed rule clause	Stakeholder	Issue	AEMC Response
		references to the 'AER' and the 'AEMC'. For example, clause 5.6.1A(f) should be amended to "…regarding the AEMC's last resort planning powers" and clause 5.6.1A(j) to "set out the AER's obligations"."	
General	Energex (p. 22)	"...defined terms that are not italicised ('non-network' and 'network augmentation' in the definition of non-network provider; 'connections' in cl.5.6.1A(b); 'design fault levels' in cl.5.6.2AA(g)(2)(iv); 'AER' and 'business day' in cl.5.6.2AA(u)&(w); 'review', 'network', 'audit', 'AER', 'publish' and 'Demand Side Engagement Strategy' in cl.5.6.5CB(f) – (h), 'cost threshold' and 'cost threshold review' in cl.5.6.5(a)(1); and 'publish' in cl.5.6.6AB(v));..."	Note that Chapter 10 terms have been italicised in the draft rule. In addition, a significant number of definitions included in new Part B of Chapter 5 are now local definitions (see draft clause 5.10.2).
General	Energex (p. 22)	"...italicised terms that are not defined ('embedded generation'' in the definition of non-network provider and in cl.S5.8(12); 'connection application'' in cl.5.6.2AA(l)(15); 'customer' in cl.5.6.2AA(g)(1)(v), 5.6.5CA(c)(4)(ii) and 5.6.6AB(p)(2); and 'capacity' in cl.S.5.8(14));..."	As above.
Miscellaneous	Energex (p. 18)	"Clause 5.6.4A(m) ENERGEX notes that clause 5.6.1A(m) contemplates that provisions analogous to clause 5.6.6AA will apply in respect of the RIT-D, yet no consequential amendments have been made to enable this to occur (see also the absence of a reference to cl.5.6.6AA in cl.5.6.5CA(g)(1))."	Noted. See section 10.3.3 of the draft determination for further discussion on this matter.
Miscellaneous	Energex (p. 22)	"ENERGEX notes that change to clause S5.1.9(j) is unnecessary as the term 'new network investment' will cease to be defined and it is not italicised in any event."	Noted. See draft rule item [16] of Schedule 1.
Miscellaneous	Endeavour Energy (p. 8)	"Seeks clarification on the meaning of the term "distribution investment"."	This term is not used in the draft rule. The draft rule used the concept of 'RIT-T project' and 'RIT-D project' to

Proposed rule clause	Stakeholder	Issue	AEMC Response
			distinguish those projects to which a regulatory investment test may be applicable (see draft clause 5.10.2 (local definitions)).
Miscellaneous	Endeavour Energy (p. 6)	"Seeks clarification on the use of the term "new network investment" as it has been deleted from the glossary in chapter 10 of the proposed rule."	Noted. References to this term have been omitted from rules.
11.30.2	Victorian DNSPs (p. 13)	"A separate and similar transitional provision should apply in relation to the application of the new Rule to joint investments. The provision should state that: • any obligation to apply the RIT-T to joint investments (including transmission-to-distribution connection investments) applies from commencement date + one year; and • any joint projects in relation to which consultation has commenced prior to commencement date + one year should continue to progress under the pre-existing Rules."	Noted. See draft clause 11.[xx].5.