AEMC

Australian Energy Market Commission

Draft Rule Determination

National Electricity Amendment (Demand Management) Rule 2009

Rule Proponent
Total Environment Centre Inc.

29 January 2009

Signed: ....

John Tamblyn
Chairman
For and on behalf of
Australian Energy Market Commission

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About the AEMC

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

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Contents

Abbreviations

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
Capex	Capital Expenditure
CMR	Congestion Management Review
Commission	see AEMC
CPRS	Carbon Pollution Reduction Scheme
DM	Demand Management
DNSP	Distribution Network Service Provider
Draft SRP	Draft Statement of Principles for the Regulation of Electricity Transmission Revenues (August 2004)
DRP	Draft Statement of Principles for the Regulation of Transmission Revenue (May 1999)
DSP	Demand Side Participation
MAR	Maximum Allowed Revenue
MCE	Ministerial Council on Energy
MNSP	Market Network Service Provider
NEL	National Electricity Law
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NEO	National Electricity Objective
NSP	Network Service Provider
NTP	National Transmission Planner
Opex	Operating Expenditure
PTRM	Post Tax Revenue Model
RAB	Regulatory Asset Base
expanded RET	20 per cent Renewable Energy Target
RIT - T	Regulatory Investment Test for Transmission
RoR	Rate of Return
Rules	National Electricity Rules

SRP	Statement of Principles for the Regulation of Electricity Transmission Revenues (December 2004). The SRP comprises a background paper and a consolidated version of the principles.
TEC	Total Environment Centre Inc.
TNSP	Transmission Network Service Provider
WACC	Weighted Average Cost of Capital

Summary

On 13 November 2007, the Australian Energy Market Commission (Commission) received a Rule change proposal from the Total Environment Centre Inc. (TEC) about increasing the requirements and incentives for use of demand management in the National Electricity Market (NEM). The Rule change proposal involves nine issues covering network planning and development, economic regulation of network service providers and elements of the wholesale market.

In accordance with section 95 of the NEL, the Commission published the TEC Rule change proposal on 22 November 2007. First round consultations closed on 1 February 2008, with twenty-nine submissions received.

In making this draft Rule determination and the draft Rule, the Commission has had regard to a range of factors including the Rule change proposal, stakeholder submissions and the requirements under the NEL.

This draft Rule determination accepts some of the TEC's proposed changes with modifications. The Commission's draft Rule incorporates the following draft changes to the National Electricity Rules (the "Rules"):

- Additional obligations on Transmission Network Service Providers (TNSPs), as part of their requirements for Annual Planning Reports. Obligations refer to providing additional information regarding characteristics of specific constraints. The information would include: extent, frequency and duration of the overload, where "overload is defined as the difference between peak load and firm capacity; and statements on the planned dates for issuing request for proposals for augmentation or a non-network alternative.

- A new obligation on the Australian Energy Regulator (AER) to accept forecast of for network support payments made in a previous regulatory period that continue in the forthcoming regulatory control period. It is noted that network support payments include payments to generators as well as DSP options that are an alternative to network augmentation. We consider this is consistent with the definition of demand management given by the TEC in their Rule Change Proposal.[1]

- A new obligation on the AER, when assessing proposed expenditure, to consider the extent to which the TNSPs have demonstrated, and made provision for, efficient non-network alternatives. To ensure that this information is available to the AER, there is an explicit obligation on TNSPs to provide information on the non-network alternatives considered by it in its Revenue Proposal.

1 TEC Rule Change Proposal (Letter dated 6 November 2007) – demand management and transmission networks.

The Commission has also determined not to accept a number of elements of the TEC Rule change proposal where those proposals were considered not to contribute to the achievements of the NEO. It is important to note that there are a range of other processes in train that are also addressing issues with regard to greater uptake of demand management in the NEM. These processes include the Review of Demand Side Participation in the NEM, and the wider Review of Energy Market Frameworks in light of Climate Change Policies.

The Commission is satisfied that the draft Rule will or is likely to contribute to the achievements of the National Electricity Objective (NEO) and has determined to make a draft Rule under section 99 of the National Electricity Law (NEL). The Commission considers the draft Rule will, or is likely to contribute to the achievement of the NEO and promote efficient investment in and efficient operation and use, of electricity services. The draft Rule seeks to improve transparency and consistency with respect to the processes of network planning and development and the economic regulation of network service providers.

The Commission invites submissions on this draft Rule determination by 13 March 2009.

In accordance with section 101 of the NEL, any interested person or body may request that the Commission hold a hearing in relation to the draft Rule determination. Any request for a pre-determination hearing must be made in writing and must be received by the Commission no later than 5 February 2009.

Submission and requests for a hearing may be sent electronically to submissions@aemc.gov.au or

by mail to:

Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

Submissions sent via email/mail should reference the following: Company/Organisation name and Demand Management Draft Determination, January 2009 – Reference ERC0047.

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1 Total Environment Centre – Demand Management Rule Change Proposal

1.1 The Rule change proposal

On 13 November 2007, the Commission received a Rule change proposal from the TEC seeking to amend the Rules to facilitate the increased use of demand management (DM) in the NEM (Rule Change Proposal).[1]

1.2 Summary of the Rule Change Proposal

The Rule Change Proposal specifically seeks to address a perceived lack of utilisation of demand management in the NEM. The proposal, whilst general in nature, particularly covers demand management issues pertaining to the processes of planning and development of networks, economic regulation of network businesses and elements of the wholesale market. The Rule Change Proposal involves nine issues that are summarised below:

1. Requiring Network Service Providers (NSPs) to consider demand management solutions before planning network augmentations;

2. Including specifications in the Regulatory Test for demand management options to be considered prior to network options;

3. Requiring TNSPs to publish robust data on upcoming network constraints that are relevant and useful to demand management service providers;

4. Requiring the AER to design and implement a demand-side incentive scheme for TNSPs;

5. Including requirements to recover expenditure on demand side activities in relation to components of the transmission determination and the post-tax revenue model;

6. Ensuring that demand management activities are appropriately integrated into revenue determinations for TNSPs;

7. Ensuring that there is an ability for NSPs to recover investment in small scale demand side activities;

8. Including a ex-post prudency review. An assessment about which TNSPs have implemented an adequate level of demand side management by documenting whether, and to the extent to which, they have proactively pursued demand management solutions; and

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1 Letter and proposal from the Total Environment Centre, 6 November 2008, *Rule change proposal demand management and transmission networks*, 6 November 2008, available at http://www.aemc.gov.au/electricity.php?r=20071115.124352

9. Including a mechanism within the wholesale market pool that allows a price to be set for demand side response services.

The TEC has asserted that its proposal will contribute to the achievements of the NEO in the following ways:

- the implementation of demand management encourages the efficient investment in, and efficient operation and use of, electricity services. Demand management is able to contribute to reducing the long term costs for consumers through avoiding unnecessary transmission network augmentations. The use of demand management can also lead to cost reflective pricing, which can have downward pressure on prices; and

- improving reliability of supply and reliability of the electricity system through the capacity of demand management to ease specific constraints at peak times and subsequently reducing overall load on the system. This reduces the risk of system failures.

1.3 New information from the TEC

On 7 October 2008, the TEC submitted additional information about its proposal for a short-term and long-term price for demand management services in the wholesale market. The supplementary material was provided to support the particular issues with respect to the lack of demand management services bidding into the NEM wholesale electricity pool.

1.4 Linkages to other work by the Commission

There are a range of initiatives being progressed either under the Ministerial Council on Energy (MCE) and by the AEMC that intersect with many of the issues raised by the TEC for improved inclusion of demand management in the NEM. In late 2007, the AEMC initiated a Review of Demand-Side Participation in the NEM. In addition, the MCE also directed the AEMC in July 2008 to undertake a comprehensive Review of Energy Market Frameworks in light of the new climate change policies being introduced.

Not-withstanding the range of other initiatives that may have importance for demand management, these Reviews are particularly relevant to the broad range of issues raised by the TEC.

1.4.1 Review of Demand-Side Participation in the NEM

The purpose of the Review of Demand-Side Participation (DSP) is to investigate the potential for amendments to the Rules in order to better facilitate efficient demand-side participation in the NEM. The objective of the Review is to identify whether there are barriers or disincentives within the Rules which inhibit efficient DSP in the NEM.

The Commission is currently undertaking Stage 2 of the Review, which seeks to identify barriers across the following five areas of the NEM:

- economic regulation of networks;
- distribution network planning;
- network access and connection arrangements;
- wholesale markets and financial contracting; and
- reliability.

The draft Report for Stage 2 of the DSP Review is expected to be released in early February 2009. The report can be accessed at www.aemc.gov.au

1.4.2 Review of Energy Market Frameworks in light of Climate Change Policies

The purpose of the MCE directed Review of Energy Market Frameworks in light of Climate Change Policies is to determine whether the existing market frameworks should be amended to accommodate the introduction of the Carbon Pollution Reduction Scheme (CPRS) and the 20 per cent Renewable Energy Target (RET). This Review is to consider both the electricity and gas markets across all states and territories.

The outcomes of this Review are to provide advice on what, if any, changes are needed to energy market frameworks, including how these changes should be implemented. The 1st Interim Report for this Review was released on 23 December 2008, with the final Report expected to be released on 30 September 2009.

This Review will be particularly important for the consideration of demand management because the introduction of a CPRS and expanded RET is expected to impact on the different and potential costs and benefits of demand side versus supply side solutions in the NEM.

1.5 Consultation and Process

On 22 November 2007, the Commission published a notice under section 95 of the NEL advising of its intention to commence the Rule change process in respect of the Rule Change Proposal.

The first round of stakeholder consultations on the Rule Change Proposal closed on 1 February 2008. The Commission received twenty-nine submissions from a range of stakeholders, including market operators, network businesses, industry participants, retailers and consumers. A complete list of stakeholder submissions is provided in Appendix A.

On 22 March, 26 August and 18 December 2008, the Commission published notices under section 107 of the NEL to extend the publication of the draft Rule determination for this Rule Change Proposal. The Commission considered it necessary to extend the publication of the draft Rule Determination in order to sufficiently analyse the range of issues common to this Rule Change Proposal, stakeholder submissions and the Reviews noted above.

1.6 Consultation on draft Rule Determination

The Commission invites submissions on this draft Rule determination by 13 March 2009.

In accordance with section 101 of the NEL, any interested person or body may request that the Commission hold a hearing in relation to the draft Rule determination. Any request for a pre-determination hearing must be made in writing and must be received by the Commission no later than 5 February 2009.

Submissions and requests for a hearing may be sent electronically to: submissions@aemc.gov.au or

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2 Draft Rule determination

2.1 Draft Rule determination

In accordance with section 99 of the NEL, the Commission has determined to make, with modifications, the draft Rule put forward by the TEC.[2] A draft of the Rule to be made (the draft Rule) is attached to, and published with, this draft Rule determination.

2.2 Commission's considerations

In making the draft Rule, the Commission has taken into account:

- the Commission's powers under the NEL to make the Rule;
- the Rule Change Proposal;
- submissions received during first round consultation;
- any relevant MCE statements of policy principles;[3]
- revenue and pricing principles;[4]
- the Commission's analysis as to the ways in which the proposed Rule will, or is likely to, contribute to the NEO; and
- other processes that intersect with the proposal.

For reasons set out in chapters two and three of this draft determination, the draft Rule satisfies the Rule making test. In brief, the Commission considers that the draft Rule will, or is likely to, contribute to the achievement of the NEO because the proposed amendments aim to improve the transparency and consistency with regard to the processes of network planning and development and the economic regulation of network service providers. The proposed amendments are likely to promote the efficient investment in, and efficient operation of and use of, electricity services.

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[2] Under section 99(3) of the NEL the draft of the Rule to be made need not be the same as the draft of the proposed Rule to which the notice under section 95 relates.

[3] For this Rule Change Proposal there are no relevant MCE statements of policy

[4] Under section 7A of the NEL, the AEMC must take into account the revenue and pricing principles in making a Rule for or with respect to any matter or thing specified in items 15 to 24 and 25 to 26J of Schedule 1 to the NEL.

2.3 Commission's power to make the Rule

The Commission is satisfied that the draft Rule falls within the subject matter for which the Commission may make Rules, as set out in section 34 of the NEL and Schedule 1 to the NEL. The draft Rule falls within the subject matters set out in section 34 (1)(a)(iii) of the NEL as it relates to:

"the activities of persons (including Registered participants) participating in the NEM or involved in the operation of the national electricity system".

The draft Rule also falls under the following subject matter items under Schedule 1 of the NEL, namely:

Item 15: "The regulation of revenues earned or that may be earned by owners, controllers or operators of transmission systems from the provision by them of services that are the subject of a transmission determination".

Item 17: "Principles to be applied, and procedures to be followed, by the AER in exercising or performing an AER economic regulatory function or power relating to the making of a transmission determination."

Item 18: "The assessment, or treatment, by the AER, of investment in transmission systems for the purposes of making a transmission determination."

Item 23: "Incentives for regulated transmission system operators to make efficient operating and investment decisions including, where applicable, service performance incentive schemes".

2.4 Assessment of the draft Rule: the Rule making test and the National Electricity Objective

2.4.1 Rule Making Test and National Electricity Objective

The Commission, in accordance with section 88(1) of the NEL, may only make a Rule if it is satisfied that the Rule will, or is likely to, contribute to the achievement of the NEO.

The NEO, set out in section 7 of the NEL, 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."

The NEO is founded on the concepts of economic efficiency (including productive, allocative and dynamic efficiencies), good regulatory practice (which refers to the means by which regulatory arrangements are designed and operated) as well as reliability, safety and security priorities.

2.4.2 Commission's assessment of the proposed Rule change against the NEO

This section sets out the Commission's assessment of the Rule Change Proposal against the NEO and the revenue and pricing principles that are required to be taken into account for this Rule change. Detailed discussion of the Commission's assessment and analysis is provided in chapter three of this draft Rule determination.

TEC Rule Change Proposals

1. **Requiring NSPs to consider demand management solutions before planning network augmentations.**

2. **Including specifications in the Regulatory Test for demand management options to be considered prior to network options.**

The proposed amendments by the TEC reflect a perceived need to balance a bias in the Rules away from investment in network augmentation to more non-network alternatives, specifically demand management options. The TEC state that implementing a more adequate level of demand management with regard to planning and development of networks would increase the efficient use of electricity services in the long term interests of consumers.

The Commission considers that the amendments sought by the TEC are unlikely to contribute to the achievement of the NEO. It is not, in the view of the Commission, appropriate to respond to perceptions of bias by introducing into the Rules new forms of actual bias. Within the Rules there are requirements to ensure that both network and non-network alternatives are considered when addressing constraints on the network. This is an appropriate principle to retain.

3. **Requiring TNSPs publish robust data on upcoming network constraints that are relevant and useful to demand management service providers.**

The TEC proposes that additional information on network constraints is needed so that demand management service providers can effectively participate and respond to upcoming constraints. Improving transparency and the level of information with respect to specific constraints is likely to contribute to the achievement of the NEO. This is particularly the case with regard to encouraging efficient investment in the planning and development of electricity networks and services for the benefit of the market and in the long term interests of consumers.

The Commission, whilst supporting the intent of this Rule Change Proposal, has proposed a modification to TEC's proposed Rule. Discussion of the modifications are provided in section 2.5 of this draft Rule determination.

4. **Require the AER to design and implement a demand side incentive scheme for TNSPs.**

The objective of this element of the Rule Change Proposal is to improve the incentives for demand management service providers to participate actively in the planning of future network developments.

The Commission considers that the amendments put forward by the TEC are unlikely to contribute to the achievement of the NEO or satisfy the revenue and pricing principles as set out in section 7A of the NEL.

The Rule Change Proposal, as put forward by the TEC, does not sufficiently recognise the incentives that already exist through the revenue cap form of price control applied for transmission networks . Under this form of price control a TNSP maximises its profits by minimising costs, irrespective of the value of any additional consumption. Therefore, any DSP at peak times that avoids costs will be profitable for the TNSP. The Commission notes that it is important to recognise that issues associated with demand management and economic regulation of networks are also being considered in the wider AEMC DSP Review.

5. **Include requirements to recover expenditure on demand side activities in relation to components of the transmission determination and the post-tax revenue model.**

6. **Ensure that demand management activities are appropriately integrated into revenue determinations for TNSPs.**

These proposed Rule changes by the TEC are to enable demand management activities undertaken by TNSPs to be appropriately recovered and incorporated into revenue determinations.

The Commission is of the view that these two proposals are likely to contribute to the efficient investment in electricity services and regulatory certainty for both market participants and consumers by improving the transparency of, and consistency between, the treatment of capital and operating expenditure arrangements in the regulatory determination process. The proposals are also viewed as compatible with the revenue and pricing principles set out in section 7A of the NEL.

The Commission supports these Rule change proposals, and has made modifications to implement the intent of the Rule change more effectively. These are provided in section 2.5 of this draft Rule determination.

7. **Ensure there is an ability for NSPs to recover investment in small scale demand side activities.**

8. **Including a ex-post prudency review. Including an assessment of TNSPs regarding the level of demand side management they have implemented. Achieved by documenting whether, and to the extent to which, TNSPs have proactively pursued demand management solutions.**

The TEC, as indicated, is seeking to improve the level of consideration of demand management options when NSPs are responding to demand growth. The proposals also seeks to improve the ability to recover expenditure on demand side activities, even when implemented on a small scale.

The Commission considers that these elements of the Rule Change Proposal are unlikely to contribute to the achievement of the NEO. The basis for the Commission's view is that the existing regime aims to ensure that the most cost-effective and efficient option is chosen in meeting regulatory obligations.

9. **Include a mechanism within the wholesale market pool that allows a price to be set for demand management services.**

The objective of the TEC Rule change proposal is to appropriately include demand side response into the wholesale electricity market. The Commission considers that the Rule change, as proposed, provides insufficient information and clarity to appropriately address its merits against the NEO, given the magnitude of the change implied. It is important to note that this issue, in the broader context, is being considered in the wider DSP Review and also within the context of issues for energy markets as a result of the introduction of the CPRS and expanded RET.

2.5 Differences between the proposed Rule and the draft Rule

The Commission has adopted some of the TEC proposed Rule changes in part and proposed modifications. These include the amount of information TNSPs provide about network constraints, the recovery of expenditure incurred by TNSPs on demand-side activities, and integration of demand management activities in the TNSPs' revenue determination processes.

The key differences between the TEC proposed Rule changes and the draft Rule are:

- The mandatory information required to be provided by TNSPs in their Annual Planning Reports about network constraints has been limited to that which is considered essential for the purposes of reducing barriers to demand management. Information is to include: extent, frequency and duration of the overload where overload is defined as the difference between peak load and firm capacity; and statements on the dates TNSPs plan issue requests for proposals for augmentation or a non-network alternative.

- The nature of the requirements for allowing expenditure to be recovered by TNSPs from demand-side activities. Transmission determinations are to include provisions requiring the AER to accept forecast of required operating expenditure in the relevant regulatory control period for network support payments made in a previous regulatory period that continue in the forthcoming regulatory control period. It is noted that network support payments include payments to generators as well as DSP options that are an alternative to network augmentation. We consider this is consistent with the definition of demand management given by the TEC in their Rule Change Proposal.[5]

- The nature of the requirement on TNSPs to allow the AER to better consider the assessment of demand management activities in the revenue determination process. The requirement will allow the AER, when assessing proposed expenditure, to consider the extent to which the TNSPs have considered, and made provision for, efficient non-network alternatives. To ensure that this information is available to the AER, there is an explicit obligation on TNSPs to provide information on the non-network alternatives considered by it in its Revenue Proposal.

5 Footnote 1 of TEC Rule Change Proposal (Letter dated 6 November 2007): "Demand management in this proposal can be read to include 'demand response', 'demand side management', 'demand side response', 'energy efficiency' and 'non-network solutions'. In general, DM can include both the management of peak loads and energy efficiency as a way of meeting capacity requirements with the greatest cost-efficiency. It includes a diverse array of activities that meet energy needs, including cogeneration, standby generation, fuel switching, interruptible customer contracts, and other load-shifting mechanisms".

3 The Commission's analysis of the Proposed Rule

This chapter sets out the Commission's analysis of the nine elements raised in the Rule Change Proposal and stakeholder submissions.[4] The analysis is grouped into three broad themes: network planning and development; economic regulation of network service providers; and operation of the wholesale market.

1. *Planning and development of networks* – requiring NSPs to consider demand management solutions before planning network augmentation.

2. *The Regulatory Test for network service providers* – including specifications in the Regulatory Test for demand management options to be considered prior to other network options.

3. *Annual Planning Reports* – requiring TNSPs to publish robust data on upcoming network constraints that are relevant and useful to demand management service providers.

4. *Development of a Demand Management incentive scheme –* requiring the AER to design and implement a demand-side incentive scheme.

5. *Recovering expenditure on demand-side activities* – allowing TNSPs to recover demand-side expenditure in relation to the components of transmission determinations and the post-tax revenue model in some circumstances.

6. *Revenue determinations* – ensuring that demand management activities are appropriately integrated into revenue determinations for TNSPs.

7. *Demand Management Expenditure* – ensuring there is an ability for NSPs to recover investment in small scale demand side activities for TNSPs.

8. *Prudency Reviews* - including an assessment of TNSPs regarding the level of demand side management they have implemented. Achieved by documenting whether, and to the extent to which, TNSPs have proactively pursued demand management solutions; and

9. *Wholesale market* - including a mechanism within the wholesale market pool that allows a price to be set for demand management services.

[4] A complete set of the stakeholder submissions can be found on the AEMC website under the TEC Demand Management Rule Change at www.aemc.gov.au.

3.1 Planning and Development of Networks

3.1.1 TEC proposal

The TEC considers there is an overall bias towards network augmentation over DM in the Rules in response to network constraints.

To address the issue, the TEC is seeking to include provisions within clause 5.6.2 of the Rules that require Network Service Providers (NSPs)[5], when responding to network constraints, to consult first on DM options before network options and provide their recommended preferred DM option. TEC indicates that a fall-back provision would be required where all cost-effective DM options have been exhausted. The TEC notes that its proposal relates to networks generally, that is both Distribution Network Service Providers (DNSPs) and TNSPs.

3.1.2 Existing arrangements

The existing framework for network planning is based on neutrality between network and non-network alternatives[6]. NSPs are obliged to undertake forecasting and planning to determine their ability to achieve standards and planning obligations.[7] The basis for these forecasts is data provided by Registered Participants in the NEM to the relevant NSP about short-and long-term electricity generation, market network service and load forecast information. [8]

NSPs are required to analyse the expected future operation of the network over an appropriate planning period taking into account the following: [9]

- the relevant forecast loads;
- any future generation, market network service; demand side; and transmission developments; and
- any other relevant data.

Where an annual planning review conducted under clause 5.6.2(b) identifies the need for an augmentation or a non-network alternative (which includes demand side response), the Rules require that the relevant NSPs undertake joint planning (that is,

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5 Where NSPs is used we are referring to both transmission and distribution businesses. Alternatively, we will refer to transmission and distribution businesses individually where an issue or point relates exclusively to them.

7 These obligations are primarily planning standards, which are referred to as reliability obligations.

8 See clause 5.6.1 of the Rules.

9 See clause 5.6.2(a) of the Rules.

between transmission and distribution businesses) to determine the plans to be considered by the relevant stakeholders.[10]

Different consultation requirements apply for transmission and distribution networks when a potential option is identified. The consultation requirements for Distribution Network Service Providers (DNSPs) are dependant on the size of the new network asset. For network assets with a cost in excess of $1 million and less than $10 million (new small distribution network assets), DNSPs are not required to consult on the network option.[11] However, they are required to carry out an economic cost effectiveness analysis of possible options to identify options that will satisfy the Regulatory Test[12] while meeting the required technical requirements of schedule 5.1 .

In addition to the economic cost effectiveness analysis identified above, for those assets that are not new small distribution network assets, the DNSPs are required to consult with stakeholders on the possible options.[13] Options can include: demand-side options; generation options; and market network service options.[14]

TNSPs are required to publish Annual Planning Reports (APR)[15] setting out the results of the planning required by clause 5.6.2(b) of the Rules. The APR must set out (among other things):

- forecast loads submitted by a DNSP in accordance with clause 5.6.1 or as modified in accordance with clause 5.6.1(d) of the Rules;
- planning proposals for future connection points;
- a forecast of constraints and inability to meet network performance requirements set out in schedule 5.1 of the Rules or relevant legislation or regulations of a participating jurisdiction over one, three and five years; and
- for all proposed augmentations to the network, information such as the project name, the reason for the constraint, the proposed solution, the total cost and other reasonable alternatives.

Network investment options identified in the APR are required to be considered under the existing Regulatory Test before being built. The stated purpose of the Regulatory Test is to identify "new network, or non-network alternatives" that maximise the net economic benefit to all those who produce, consume and transport electricity in the market, or in the event the option is necessitated to meet the service standards linked to the technical requirements of schedule 5.1 or in applicable

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10 See clause 5.6.2(c) of the Rules.

11 See clause 5.6.2(f) of the Rules.

12 The Regulatory Test is a test required to be undertaken by NSPs before augmenting the network. There are two limbs to the test, a market benefits limb and a reliability limb.

13 See clause 5.6.2(g) of the Rules.

14 See clause 5.6.2(f) of the Rules. In addition to the requirements under the NER, DNSPs have detailed jurisdictional planning obligations. These obligations differ between the jurisdictions.

15 Clause 5.6.2A(a) of the Rules.

regulatory instruments, minimise the present value of costs of meeting those requirements.[16][17] The current Regulatory Test requires that alternative options are to be considered "without bias", where an alternative option is defined as:

> "An alternative option may be, without limitation, a generation option, demand side management/response option, network option, the substitution of electricity by the previous of alternative forms of energy, or a combination of these".[18]

It is important to note that as part of the AEMC National Transmission Planner Review (NTP), as directed by the MCE, the Commission recommended an alternative design for the Regulatory Test as it related to transmission. In particular, the recommendation included that the reliability and market benefits limbs of the test be combined. Based on the recommendations, the AEMC is currently developing a revised Regulatory Test (know as the Regulatory Investment Test for Transmission (RIT-T)). Further information on the current reforms is provided in the next section.

3.1.3 Stakeholder views from first round consultation

Stakeholder submissions raised a range of key issues with respect to this aspect of the Proposed Rule Change The stakeholders[19] that supported the Rule Change Proposal, in principle, noted:

- there is presently a strong bias towards augmentation, and demand management should be prioritised and considered properly with other options. It was noted that there have been significant achievements from overseas (e.g. the Californian) demand management programs that should be considered;

- in most cases NSPs were considered to reject a non-network alternative that does not comply with all of an NSPs requirements/obligations. NSPs should consider a combined augmentation program that takes advantage of the non-network alternative where that alternative complies with part of the NSP's requirements/obligations;

16 Clause 5.6.A(b) of the Rules.

17 It is important to note that the existing Regulatory Test is being revised and replaced with the Regulatory Investment Test for Transmission (RIT-T).

18 AER Regulatory Test v3 final decision, p. 56.

19 J. Goddard, Fuji Xerox Australia Pty Ltd, Investa Properties Ltd, Mudgee District Environment Group Inc, Inghams Enterprises Pty Ltd, CVC Limited, Stormlight Consulting Pty Ltd, Energetics Pty Ltd., Mudgee District Environment Group, Alternative Technology Association (ATA), Griffith Law School Centre for Credit and Consumer Law (Griffith) and Energy Response. Next Energy was generally supportive of proposals that prioritised demand management ahead of building new supply infrastructure. GridX agreed with TEC that there is a cultural bias toward supply-side solutions over demand-side solutions.

There were a number of submissions[20] that did not support the Rule Change Proposal and those indicated the following:

- the importance to consider both demand-side and supply side options concurrently and on an equal basis when addressing network constraints;
- the proposal would effectively require demand-side options to be preferred ahead of potentially more efficient network solutions which would be inconsistent with the national electricity objective;
- non-network alternatives include "demand management" and thus it is viewed that there is no need to specifically reference demand management as an option;
- the Rules allow for TNSPs to consider demand management options as solutions to network constraints. It was noted that TNSPs do consider demand management options in their planning arrangements;
- there are currently other processes such as the AEMC NTP Review that are considering some of the issues raised by the Rule Change Proposal; and
- the current arrangements do not over-reward network investment as regulatory decisions are a potential source of uncertainty due to potential changes in the weighted average cost of capital (WACC) parameters.

3.1.4 Commission's consideration and reasoning

The Commission notes that Chapter 5 of the Rules seek to ensure that TNSPs and DNSPs consider both network and non-network alternatives in their general network planning arrangements. It is also noted that the consultation obligations on NSPs enable other parties to either submit proposals or challenge the assessment of the NSP.[21] These arrangements aim to ensure there is no bias towards a particular technology or response in the Rules and that all relevant options are identified.

The Commission considers that the amendment as proposed by the TEC may result in an efficient network solution, where identified, being overlooked due to the bias for DM options. This is likely to drive inefficiencies and magnify costs by providing DM service providers with market power in respect of the services TNSPs would, in effect, be obliged to buy under the proposal. This is also likely to increase the costs of providing electricity to consumers.

Based on this analysis, the Commission has determined not to accept this element of the TEC Rule Change Proposal in this draft Rule.

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[20] Ergon Energy, ERAA, ETNOF, ENA, ESAA, SP AusNet, Energex, TRUenergy and NGF. ETSA Utilities and CitiPower and Powercor stated generally that demand management should be considered as an option and not necessarily as a superior alternative.

[21] Where it is above the relevant threshold.

3.2 The Regulatory Test for Network Service Providers

3.2.1 TEC proposal

The TEC is concerned that the provisions for the Regulatory Test do not appropriately include demand-side options in the assessment of costs and/or benefits. Specifically, the TEC notes that the consideration of alternative options includes the term 'may', which does not represent a requirement, or even encouragement, to investigate more efficient solutions. In addition, TEC indicates that the focus on those who 'produce, consume and transport' electricity assumes that the interests of those that produce and transport electricity are aligned with and equal to the long-term interests of consumers.

TEC propose to amend clause 5.6.5A of the Rules to include requirements in the Regulatory Test that allow for demand-side options, or other non-network alternatives to be identified first. The consultation and analysis is then to focus on the demand side option and consider all genuine alternatives to that option.

3.2.2 Existing arrangements

Clause 5.6.5A of the Rules requires the AER to develop and publish a Regulatory Test. As discussed in section 3.2.1, the purpose of the Regulatory Test is to identify new network investments or non-network alternative options that will maximise the net economic benefit to all those who produce, consume and transport electricity in the market or in the event the option is necessitated to meet the service standards linked to the technical requirements of schedule 5.1 or in applicable regulatory instruments, will minimise the present value of the costs of meeting those requirements.[22]

The current formulation of the regulatory test has two limbs – the market benefits limb and a reliability limb. Section 5.6.5A(c)(3) of the Rules states that the Regulatory Test must:

> "ensure that the identification of the likely alternative option referred to in subparagraph (1) is informed by a consideration of all genuine and practicable alternative options to the proposed *new network investment* without bias regarding:
>
> (i) energy source
>
> (ii) technology
>
> (iii) ownership"

As indicated, there are a number of consultation requirements on network service providers. A detailed discussion of these requirements is given below:

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[22] Clause 5.6.5A(b) of the Rules.

DNSPs

For assets valued in excess of $1 million and less than $10 million (new small distribution network assets) DNSPs are not required to undertake any consultation.[23]

However, for projects valued over $10 million, DNSPs are required to consult with affected Registered Participants, NEMMCO and interested parties on the possible options, including but not limited to demand side options, generation options and market network service options, to address the projected limitation of the relevant distribution system. In addition, DNSPs are required to carry out an economic cost effectiveness analysis of possible options. This is done in order to identify options that will satisfy the Regulatory Test while meeting the technical requirements of schedule 5.1[24] and make it available to interested parties[25]. DNSPs are then required to report on the outcomes of this analysis.

TNSPs

For TNSPs, if the proposed asset is a new small transmission network asset, the TNSP is required to explain the ranking of reasonable alternatives to the project including non-network alternatives) to report on the inter-network impacts, and provide analysis of why it considers it satisfies the Regulatory Test in its APR. Stakeholders may make written submissions within 20 business days of the publication of the APR.[26]

For new large transmission network assets that are to be assessed against the market benefits limb of the Regulatory Test, TNSPs are required to publish a Request for Information (RFI) as to the identity and detail of alternative options to the potential new large transmission network asset and details of the proposed new large transmission network asset.[27] Before the TNSP can publish the application notice for a proposed new large transmission network asset, it must publish the RFI on its website and provide an RFI notice to NEMMCO. The RFI notice is to specify the due date for submissions (a minimum of eight weeks after the publication of the RFI notice). Under the Regulatory Test[28] the RFI is to include:

- details of the potential or proposed asset, including all of the relevant technical details, the proposed construction timetable, the commissioning date and all known expected costs and the likely sources of costs and market benefits associated with the proposed asset;

[23] See clause 5.6.2(f) of the Rules.

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

[25] See clause 5.6.2(h) of the Rules.

[26] See clause 5.6.6A of the Rules.

[27] See clause 5.6.5A(c)(4) of the Rules.

[28] See clause 5.6.6 of the Rules.

- reasons for the potential asset, including how the asset satisfies these reasons and, where applicable, any network limitations, reliability requirements or specific planning criteria;

- known existing and planned infrastructure in the geographic region, including relevant network and generation assets;

- load forecasts in the geographic region for the next ten years, including peak demand and load profiles;

- any specific project requirements that an alternative option must fulfil, including any technical or other limitations such as speed of response, size, type and location of loads to be reduced , shifted substituted and size, type and location of generation to be installed or utilised; and

- a description of the process for assessing alternative options, including evaluation criteria.

3.2.3 Stakeholder views from the first round consultation

The majority of stakeholders that rejected the proposal did so on the basis that it would impact on competitive neutrality within the Rules and that it would be inconsistent with the National Electricity Objective.[29] VENCorp suggested, however, that the RFI process could be extended to both limbs of the Regulatory Test.

The stakeholders that supported this proposal noted that demand management solutions should be investigated before augmentation options. In doing so it is likely to ensure that demand management receives a more appropriate level of attention from TNSPs. In addition, there was support for demand management options to be considered before augmentation options provided this did not create a bias against essential augmentation.[30]

3.2.4 Commission's consideration and reasoning

The Commission notes that the existing arrangements for network planning and augmentation seek to ensure that TNSPs consider network and non-network alternatives under the Regulatory Test where they will maximise the net economic benefit to all those who produce, consume and transport electricity in the market or in the event the option is necessitated to meet the service standards linked to the

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29 Ergon Energy, Energex, ERAA, ENA, TRUenergy, ETNOF, ESAA and NGF. ETSA Utilities and CitiPower and Powercor stated generally that demand management should be considered as an option and not necessarily as a superior alternative.

30 J. Goddard, Fuji Xerox Australia Pty Ltd, Investa Properties Ltd, Mudgee District Environment Group Inc, Inghams Enterprises Pty Ltd, CVC Limited, Stormlight Consulting Pty Ltd, Energetics Pty Ltd., ATA and Griffith. Next Energy was generally supportive of proposals that prioritised demand management ahead of building new supply infrastructure.

technical requirements of schedule 5.1 of the Rules or in applicable regulatory instruments, minimise the present value of the costs of meeting those requirements.

In addition to the network planning requirements, the existing Regulatory Test also provides requirements for NSPs to identify network and non-network alternatives without bias.

The Commission considers that the TEC proposal is likely to drive inefficiencies by introducing a bias in favour of demand management over all other alternatives. Introducing a bias such as proposed would remove the existing neutrality that is built into the current market design.

It is acknowledged, however, that the current threshold for consultation in the existing Regulatory Test (based on the value of the network option) may create the perception of a bias towards network options. The reforms being progressed by the Commission to develop a National Framework for Transmission Planning includes, as noted, the development of a revised RIT-T. It is expected that these proposed new arrangements will assist to address the perception of bias raised by the TEC. It is also important to note that the broader issues relating to other perceived bias such as the Regulatory Test for DNSPs is also being considered in the recent MCE decision to direct the AEMC to conduct a Review of National Framework for Electricity Distribution Network Planning and Expansion.[31]

TEC also proposed that the Regulatory Test should have the purpose of maximising the long-term benefits to consumers, rather than those who 'produce, consume, and transport' electricity. Economic efficiency requires that:

- the production of electricity occurs at its lowest efficient cost;
- the amount of goods and services supplied and their prices reflects their value to consumers and the efficient costs to supply them; and
- the outcomes of the above support efficient long-term investment over time.

These objectives are consistent with the long-term interests of consumers and therefore form a fundamental element of assessments against the NEO.

The current principle of the Regulatory Test to maximise the net economic benefits to those who 'produce, consume, and transport' electricity is consistent with the economic efficiency outcomes identified above. This is because wealth transfers from one party to the next do not improve overall efficiency but simply shift the benefits to a different party. In particular, supporting long-term investment over time requires that producers and transporters of electricity face efficient signals for investment into the future. On that basis, it is recommended that the purpose of the test remain in its current form. The Commission therefore on this basis has determined not to accept this proposal into the draft Rule.

[31] http://www.mce.gov.au

3.3 Annual Planning Reports

3.3.1 TEC Proposal

The TEC considers that there is failure of TNSPs to properly investigate DM properly, due to a lack of information, (i.e. characteristics of constraints) available to prospective demand management providers.

The TEC proposes the following additional information regarding constraints be provided (within clause 5.6.2A) routinely by TNSPs:

- total capacity, firm delivery capacity and peak load;
- extent of overload (peak load > firm capacity; MVA);
- frequency of overloads (days per annum where peak load > firm capacity);
- length of overloads (hours per annum where peak load > firm capacity);
- power factor at time of peak load;
- load trace/data for (current actual) peak day;
- annual load duration curve/data;
- distribution networks connected to constrained asset; and
- a statement of whether the TNSP plans to issue a Request for Proposal (RFP) for electricity system support and if so, the expected date the RFP will be issued.

In addition, the TEC considers that there is a lack of ex-post reporting of DM which makes it impossible for regulators and consumers to assess the degree to which networks are utilising an adequate level of demand management. The TEC also proposes extending the period in which constraints are to be identified in forecasts to ten years.

3.3.2 Existing arrangements

As part of their APRs, TNSPs are required to provide information about the forecast of constraints and inability to meet performance requirements as set out in schedule 5.1 of the Rules or relevant legislation or regulations of a participating jurisdiction over one, three and five years (cl 5.6.2A(b)). However, currently there is no prescription on the information TNSPs are required to report on with regard to the constraints they identify.

Regarding ex-post reporting of DM activity, where an augmentation solution has been identified, TNSPs are required to provide information on other reasonable network and non-network options considered to address the actual or potential constraint or inability to meet the network performance requirements of the network.[32] In this regard, other reasonable network and non-network options include, but are not limited to, interconnectors, generation options, demand-side options, market network service options and options involving other transmission and distribution networks (cl 5.6.2A(b)(4)(vi)).

3.3.3 Stakeholder views from the first round consultation

Stakeholder submissions generally supported the intent of the proposal by the TEC. The key issues raised included:

- publishing robust data which is relevant and useful to demand management providers would inform demand management providers of upcoming opportunities and enable them to effectively respond;[33]
- the information should be relevant for providers of all potential solutions to upcoming constraints;[34]
- the provision of data should be proportionate to the costs of providing such information;[35]
- implementing a national regime for reporting of upcoming constraints needs to be proportionate to the benefits. Consideration should be given to developing a nationally consistent demand management information disclosure regime for NSPs;[36]
- the existing regime already ensures that a substantial amount of information about emerging constraints is provided to the market for demand management providers to offer potential solutions;[37] and
- the current publication of the Annual Network Transmission Statement (ANTS) could include information for demand management.[38]

In addition, the NSW Minister for Energy noted that sound network planning requires transparency and consistent disclosure of relevant information, including

[32] The Rules do not prescribe what information is to be provided.

[33] J. Goddard, Fuji Xerox Australia Pty Ltd, Investa Properties Ltd, Mudgee District Environment Group Inc, Inghams Enterprises Pty Ltd, CVC Limited, Stormlight Consulting Pty Ltd and Energetics Pty Ltd, ATA and Griffith.

[34] TRUenergy, NGF, ERAA.

[35] VENCorp, ENA.

[36] ENA.

[37] ETNOF.

[38] NEMMCO.

network constraints, areas of demand growth and estimated costs of network augmentation.[39]

3.3.4 Commission's consideration and reasoning

The Commission notes that information on the characteristics of constraints, as proposed by TEC is likely to assist proponents of non-network alternatives to determine their suitability to potentially addressing a particular constraint on the network. That is, DM proponents could match their capability to address a constraint with the characteristics of the constraint. For example, a DM service provider may only be able to provide demand reduction services for limited periods of time. Information about the duration of a constraint may assist that DM proponent in determining its suitability to address the constraint.

The Commission notes that providing information such as the characteristics of a constraint is data that should be already collected by TNSPs as part of their load flow modelling forecasts so that they can determine when to act, and what action is required, to address a constraint.

The benefits of constraint information was recognised in the Congestion Management Review (CMR) completed by the AEMC in June 2008[40] that recommended the introduction of a Congestion Information Resource (CIR). Specifically the Rules would require NEMMCO to develop and publish a resource that provides information in a cost-effective manner to market participants that would enable them to understand the patterns of congestion and to plan projects with respect to market outcomes in the presence of network congestion. This resource would provide a complementary information resource to that sought by this proposal.

The Commission considers that any additional information about the characteristics of a constraint is likely to have broader benefits. For example, details about the characteristics of a constraint would assist potential new generators in determining the potential dispatch risk or mis-pricing risk of locating at a particular location.

The Commission does however note that whilst additional information to support non-network alternatives is beneficial, there is a need to ensure that this is balanced against the burden of providing such information. In this context, the Commission considers that where information is already being generated to inform network planning, the net additional cost of making this information available in an accessible form for DM providers should be relatively low.

It is therefore considered that the following information which is considered by the Commission as most essential should be provided. The recommended new information includes:

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[39] NSW Minister for Energy.

[40] AEMC, *Congestion Management Review: Final Report*, June 2008.

– the extent to which peak load is greater than firm capacity (the 'overload');

– the number of days in which overload is likely to occur in that financial year;

– the number of hours in which overload is likely to occur in that financial year; and

– a statement of whether the Transmission Network Service Provider plans to issue requests for proposals for augmentation or a non-network alternative identified by the annual planning review conducted under clause 5.6.2(b) and if so, the expected date the request will be issued.

The Commission also considers that there are benefits from TNSPs providing a statement in their APRs about whether they intend to issue a RFP for electricity system support and details of when they expect to release it. This will assist in the preparedness of potential network alternatives to respond to the TNSP's RFP and potentially lower the administrative costs of consultation.

The Commission notes that the TEC has proposed to extend the timeframe for which information about constraints is provided (from five to ten years) and to include ex-post reporting of DM activities in the APRs. Information that extends out to a ten year timeframe is likely to be highly speculative and uncertain, predominately due to the nature of information available. With respect to ex-post reporting of DM activities in the APRs, the Commission notes that the TNSPs are already required to provide the details of non-network alternatives considered to address a network issue, thus there does not appear to be a need to provide further information in this regard.

3.4 Development of a Demand Management Incentive Scheme for TNSPs

3.4.1 TEC Proposal

The TEC considers that TNSPs consistently overlook DM due to the failure of the Rules to provide adequate incentives for its inclusion. The TEC considers that TNSPs have a large incentive to augment their networks due to their ability to earn a return on those capital investments.

The TEC propose to introduce an incentive scheme for TNSPs to be developed by the AER which is largely based upon the scheme for New South Wales DNSPs. The proposed scheme would provide additional revenue to a TNSP if demand on the transmission system is reduced when the system is constrained.

3.4.2 Existing arrangements

There are a number of arrangements in the existing economic regulation framework that contribute to the incentives for TNSPs to undertake efficient investment. These include:

- a CPI-X revenue cap which rewards outperformance and penalises under-performance relative to the capped revenue forecast;
- capital expenditure that has been incorporated into the TNSP's Regulatory Asset Base (RAB) will not be removed from the RAB;[41]
- capital expenditure incentives that include both depreciation and the cost of capital in the calculation of associated rewards and penalties;
- an allowed rate of return based on benchmark assumptions to encourage TNSPs to pursue strategies to lower their cost of capital relative to the regulatory allowance; and
- an operating expenditure efficiency incentive scheme that provides for symmetrical rewards and penalties which can be carried over to the next period to provide a consistent strength of incentive in each year of the regulatory control period.

41 Except in specific circumstances where the TNSP has failed to reasonably manage the risks of commercial stranding.

3.4.3 Stakeholder views from the first round consultation

Those submissions[42] that supported the change were of the view that networks generally did not invest in cost-effective demand management and the incentive scheme developed by the AER would be beneficial. It was noted that experience with the "D–Factor" incentive scheme for New South Wales DNSPs demonstrated that demand management opportunities are available and that there are benefits in implementing such opportunities.[43]

Generally, those stakeholders that were not in support of the proposal noted the following key issues:

- there should be consideration of the costs and benefits of setting up such a scheme;[44]
- demand management along with other non-network alternatives should form part of the competitive market. Providing regulated incentives for transmission DM would create a bias towards demand management over other viable non-network options – leading to inefficient outcomes and potentially higher costs for consumers;[45]
- risk averse behaviours by NSPs may result in disincentives to using demand management, and enhancement of demand management firmness and technologies and a reduction in the barriers to entry for DM aggregators will lead to more efficient outcomes than through incentives to facilitate a regulated approach to DM;[46]
- the current chapter 6A of the Rules is designed to provide appropriate incentives for efficient network investment and it is unlikely that it needs revision soon after its establishment. A revenue cap provides a natural incentive for TNSPs to adopt efficient solutions to address a network need;[47]
- there could be greater financial incentives to encourage demand management solutions, although not necessarily as suggested in the Rule change, e.g.

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42 Cool NRG, Energy Response, J. Goddard, Fuji Xerox Australia Pty Ltd, Investa Properties Ltd, Mudgee District Environment Group Inc, Inghams Enterprises Pty Ltd, CVC Limited, Stormlight Consulting Pty Ltd, Energetics Pty Ltd., ATA and Griffith.

43 ATA.

44 TRUenergy, Energex.

45 NGF.

46 NGF.

47 ETNOF.

consideration should be given to international models such as California's incentive scheme for energy efficiency;[48]

- an incentive scheme would amount to a preferential subsidy for demand management and would be inconsistent with the National Electricity Objective;[49] and
- consideration should be given to the introduction of specific demand management incentives to assist in the development of NSPs demand management capability and to facilitate the development of a demand management provider market.[50]

3.4.4 Commission's consideration and reasoning

The Commission notes that TNSPs operate under a regulated revenue cap and are required to forecast both capital and operating expenditure for each year of the regulatory control period. Where the AER determines the forecasts to be efficient, the maximum revenue that can be earned by the TNSP is capped at a level consistent with recovering efficient operating costs, depreciation and reasonable return on past capital expenditure, and efficient future capital expenditure. Under this form of price control a TNSP maximises its profits by minimising costs, irrespective of the value of any additional consumption. Therefore, any DSP at peak times that avoids costs will be profitable for the TNSP.

A revenue cap provides strong incentives for the TNSP to minimise costs because a regulated business is able to earn larger profits by reducing costs. Demand management can be an effective way for TNSPs to reduce costs. For example, if the cost of encouraging demand management is less than the cost of an augmentation, then a TNSP will obtain an additional profit equal to the cost difference between the two options. The Commission is not, therefore, persuaded that incentives need to be further strengthened through an additional DSP-specific incentive scheme. The broader issue of whether the incentives under a revenue cap result in the most efficient level and use of DSP, having regard to the value to consumers of energy use, is being further examined in the Stage 2 of the DSP Review.

The Commission, on this basis, has determined not to accept the TEC proposal for a demand side incentive scheme because of the existing incentives that TNSPs have to minimise costs, including through the procurement of DSP. As noted above, further consideration of the overall efficiency of incentives is being considered in the DSP Review.

48 ETNOF, Energex.

49 ETNOF, ERAA.

50 ENA.

3.5 Recovering expenditure on demand-side activities

3.5.1 TEC proposal

The TEC considers that the absence of an incentive scheme is exacerbated by the lack of certainty regarding the ability of TNSPs to recover DM expenditure. The proposal indicates that there is a lot of detail regarding the recovery of expenditure on the asset base, however, there is little detail on how a transmission network is to recover either operational or capital expenditure on DM activities.

TEC's proposal includes adding references to demand-side expenditure in relation to the components of transmission determinations and the post-tax revenue model (Chapter 6A).

3.5.2 Existing arrangements

The Rules allows TNSPs to recover expenditure towards the supply of prescribed transmission services (i.e. shared network services) where DM can be a contributor towards providing those services.

Once expenditure is incurred, there is a different risk of recovery between capital and operating expenditure. Capital expenditure enters the RAB at the following determination without a review of prudency and efficiency. In contrast, the AER can effectively challenge the prudency of any ongoing operating expenditure items, and potentially deem it to be inefficient. Therefore, when the AER is assessing operating expenditure at the next revenue determination, it can make an assessment about the prudency and efficiency of this expenditure.

3.5.3 Stakeholder views from the first round consultation

Generally it was noted that there could be greater clarity in chapter 6A about the recover of DM costs.[51] Specifically it was noted that the circumstances in which TNSPs can recover spending on DM must be clarified, as it would create more certainty for networks.[52]

Key issues from those stakeholders who did not support the proposal included:

- issues noted in the proposal, including properly balancing the differing economic incentives between capex and opex, are broad and better addressed in the wider AEMC DSP Review;[53]

51 ETNOF, SP AusNet.

52 J. Goddard, Fuji Xerox Australia Pty Ltd, Investa Properties Ltd, Mudgee District Environment Group Inc, Inghams Enterprises Pty Ltd, CVC Limited, Stormlight Consulting Pty Ltd, Energetics Pty Ltd, ATA and Energex.

53 ENA.

- the current arrangements already provide clear specifications of the circumstances in which TNSPs can recover these expenditures;[54]
- a view that the proposed Rule change would not improve the clarity in the Rules regarding the recovery of DM expenditure;[55] and
- that DM incurred by TNSPs can be recovered via a pass-through application but that any uncertainty in the Rules regarding this should be clarified.[56]

3.5.4 Commission's consideration and reasoning

The Commission notes that there appears to be a difference in certainty of cost recovery between capital and operating expenditure. A long-term commitment incurring operating costs has a greater risk of a subsequent regulatory determination resulting in an inability to recover costs fully. Box 1 provides an example of the current imbalance of risks between recovering capital and operating expenditure.

Box 1: Example

For example, if there are two options to address a particular constraint, a network option of $1 million and a DM option of $0.8 million (the DM option will require payments to a consumer of $100,000 per year for eight years). If the TNSP undertook the network option at any time during the regulatory period they would build it for $1 million and roll that amount (minus depreciation) into its RAB at the next revenue reset without any risk of optimisation.

Alternatively, if the TNSP chose the DM option and commenced payments in year three of the Regulatory period, by the end of the regulatory control period it would have paid $300 000 to the DM proponent. At the start of the next regulatory control period it would, under its contract with the DM proponent, be required to fund an additional $500 000 over the next five years.

Under the existing arrangements, the TNSP faces the risk that it will not be provided with a revenue allowance for the remaining $500 000 at the next revenue determination. This is because, unlike the network option, it is required to seek approval from the AER at the next reset to fund that additional amount.

The difference in treatment between operating and capital expenditure increases the risk of recovery with regard to operating expenditure. The Commission considers that this may create a bias against DM initiatives as they incur operating expenditure.

A mechanism to address this issue is to make risks of operating expenditure align with that of capital expenditure with regard to non network support solutions. This can be achieved by including a requirement that the AER should accept forecasts of

54 ERAA, TRUenergy.

55 ETNOF.

56 TRUenergy, NGF.

operating expenditure for network support payments made in a previous regulatory period that continue in the forthcoming regulatory control period. It is noted that network support payments include payments to generators as well as DSP options that are an alternative to network augmentation. The Commission considers this is consistent with the definition of demand management given by the TEC in their Rule Change Proposal which states:

> *"Demand management in this proposal can be read to include 'demand response', 'demand side management', 'demand side response', 'energy efficiency' and 'non-network solutions'. In general, DM can include both the management of peak loads and energy efficiency as a way of meeting capacity requirements with the greatest cost-efficiency. It includes a diverse array of activities that meet energy needs, including cogeneration, standby generation, fuel switching, interruptible customer contracts, and other load-shifting mechanisms".*

The Commission considers that this solution more effectively meets the desire of the TEC to clearly specify the recovery of DM expenditure and give recognition to the operational and capital expenditure trade-offs than simply identifying that DM expenditure can be recovered as proposed. This is also consistent with the revenue and pricing principles given in Section 7A of the NEL.

Based on this assessment, the Commission has determined to accept the proposed Rule change, with modifications.

3.6 Revenue determinations – integration of demand management activities

3.6.1 TEC proposal

The TEC considers that the current regulatory approach is biased towards supply-side options as a result of the current revenue determination process for TNSPs. The TEC considers that supply-side approaches are prioritised in the revenue determination process, which gives them the advantage of incumbency as the preferred option. Once these supply-side solutions are investigated, they consider it unlikely that a demand side activity will be successful.

The TEC therefore proposes to include a number of amendments into chapter 6A of the Rules. These principally involve additional requirements with regard to the arrangements for forecast operating and capital expenditure.

3.6.2 Existing arrangements

Clauses 6A.6.6 and 6A.6.7 of the Rules require the AER to assess the proposed forecast capital expenditure and forecast operating expenditure in accordance with expenditure objectives, criteria and factors:

- The expenditure objectives are: meeting expected demand; complying with applicable regulatory obligations; and maintaining quality, reliability and security of supply and the reliability, safety and security of the transmission system.

- The expenditure criteria are those that the AER must be satisfied the forecast of required revenue has achieved. These include that the forecast reasonably reflects: efficient costs; the costs of a prudent operator in the circumstances of the TNSP; and a realistic expectation of demand and cost inputs.

- The expenditure factors are evidentiary matters the AER should have regard to in undertaking its assessment and include: the submissions made by the TNSP and interested parties; analysis presented by the TNSP in its proposal and by the AER itself; benchmark data; and the actual and expected expenditure of the TNSP during any preceding periods.

Of particular relevance to DM are the evidentiary expenditure factors relating to the considerations of potential substitution possibilities between forecast capital expenditure and forecast operating expenditure and the requirement that the expenditure reflects benchmark expenditure by an efficient TNSP over the period.

3.6.3 Stakeholder views from the first round consultation

A range of submissions did not support the proposal. Key issues included:

- DM can already be integrated into revenue determinations;[57]

- an incentivised regulatory framework recognising the different risk profiles of non-network alternatives need to be firstly introduced;[58] and

- the regulatory regime should treat network and non-network solutions equally;[59]

- the incentive scheme needs to be correctly tuned so that there are not perverse incentives to pursue DM towards the start of a regulatory period;[60] and

- a balanced approach to network DM requires similar treatments towards capital and DM operating expenditure.[61]

Other submissions that supported the intention of the proposal noted that revenue determinations are an ideal process to facilitate demand management and that demand management should be prioritised ahead of augmentations.[62] It was also

57 TRUenergy, ERAA.

58 Energex.

59 NGF.

60 Energy Response, ENA.

61 ENA, .

62 J. Goddard, Fuji Xerox Australia Pty Ltd, Investa Properties Ltd, Mudgee District Environment Group Inc, Inghams Enterprises Pty Ltd, CVC Limited, Stormlight Consulting Pty Ltd, Energetics Pty Ltd, ATA and Griffith.

noted that clarifying the recovery of costs of non-network alternatives would be beneficial.[63]

3.6.4 Commission's consideration and reasoning

The Commission notes that the expenditure criteria provides the basis upon which the AER is to accept a TNSP's forecast expenditure. The expenditure factors provide a list of considerations the AER should give regard to in making its assessment. As they form an evidentiary basis for the AER, S6A.1.1(1) and S6A.1.2(1) of the Rules require that the TNSP's proposed expenditure complies with the requirements for forecast expenditure, which includes the expenditure objectives, criteria and factors. This places a requirement on TNSPs to demonstrate how their proposal is consistent with these elements.

The Commission considers, however, that there is not an explicit focus given within the evidentiary factors to ensuring that appropriate non-network alternatives have been considered by TNSPs or the AER (although it could be argued that this is implicit in some of the criteria, such as the substitution possibilities between capital and operating expenditure).

In order to improve transparency and to ensure that alternatives are appropriately considered, the Commission has determined to accept the TEC proposal, with modifications. The Commission proposes to include a requirement on TNSPs to set out any non-networks alternatives they have considered in their Revenue Proposals and a requirement on the AER to "consider the extent that TNSPs have considered, and made provision for, efficient non-network alternatives".

The Commission notes that a similar provision has been included in the distribution revenue Rules in Chapter 6. Therefore, including the provision for transmission is likely to improve the consistency between the arrangements.

3.7 Demand Management Expenditure - recognition of the potential use and value of small-scale demand-side activities

3.7.1 TEC Proposal

The TEC considers that a major barrier to the implementation of DM is the inability of networks to recover expenditure on modest (small scale) DM investments. The TEC considers that while such expenditure may not directly contribute to the alleviation of a particular constraint at a particular time, it is likely that accumulated will.

The TEC proposes to include a requirement to consider DM options when undertaking an assessment of alternatives under the Regulatory Test. In that way,

63 ETNOF.

the TNSP would be able to better recover expenditure towards small-scale DM investments.

3.7.2 Existing arrangements

As noted, TNSPs are subject to a revenue cap with a number of incentives related to minimising capital and operating expenditure. In addition, there are requirements within the Rules with regards to pricing. Clause 6A.23.4(e) of the Rules requires that prices for recovering the locational component of transmission services must be based on demand at the times of greatest utilisation of the transmission network and for which network investment is most likely to be contemplated. The principle behind this Rule is that transmission customers should face charges that reflect the long-run marginal costs of supply.

3.7.3 Stakeholder views from first round submissions

Submissions that supported the proposal noted that small-scale DM activities should be enabled even when unrelated to particular constraints and that multiple small-scale DM can collectively provide effective DM.[64]

Those submissions that did not support the proposal considered that there would be high transaction costs in recognising those small-scale DM options, particularly in the context of transmission. It was also noted that modest DM initiatives are much more likely to occur in distribution networks.[65]

3.7.4 Commission's consideration and reasoning

The Commission notes that under the existing arrangements, TNSPs have incentives to procure non-network alternatives (including DM) where these are a lower cost option than a network option. TNSPs are also encouraged by the existing regime and incentives to choose the most cost-effective and efficient option to ensure their planning obligations are met. On this basis, there is nothing precluding a DM option. It is noted, however, that if a small-scale option does not meet the specific technical requirements that are required, the TNSP is then at risk of not meeting its planning obligations, and as a result it may contravene the conditions of its licence.[66]

If, however, as the TEC proposes, TNSPs undertook spending for DM that does not avoid or defer an augmentation, the costs of operating the network would increase without a corresponding benefit. This is because TNSPs are given revenue to undertake efficient expenditure with regard to the expenditure objectives as outlined

64 ATA, Griffith, Energex, J. Goddard, Fuji Xerox Australia Pty Ltd, Investa Properties Ltd, Mudgee District Environment Group Inc, Inghams Enterprises Pty Ltd, CVC Limited, Stormlight Consulting Pty Ltd, Energetics Pty Ltd, Cool NRG.

65 ENA, NGF, ENTOF.

66 Note, however, that this risk would be factored into an assessment that was conducted under a probabilistic approach as occurs in Victoria.

in previous sections. Any additional discretionary expenditure, such as for DM that does not avoid a constraint or achieve a planning obligation, will not provide a corresponding benefit to customers (as no additional service is provided) and will also reduce the profit of the TNSP (which will impact on long-term efficiency outcomes).

Based on this analysis, the Commission has determined not to accept this element of the Rule Change Proposal in this draft Rule. The Commission notes however that similar issues are being considered in the wider DSP Review, particularly with respect to the incentives available for allowing expenditure on innovative demand side activities.

3.8 Prudency reviews – assessment of the extent to which transmission network service providers have implemented an adequate level of demand management

3.8.1 TEC Proposal

The TEC considers that NSPs consistently overlook or ignore DM when considering how to respond to demand growth. In addition, the TEC notes that almost all failures to harness efficiency through DM are overlooked by regulators, at the expense of the long-term interests of consumers. TEC proposed that expenditure on DM should be reviewed ex post, and where appropriate expenditure should be disallowed where cost-effect DM had been ignored.

3.8.2 Existing arrangements

The current regime is based on setting ex ante allowance based on forecast efficient costs, and relying on financial incentives to promote efficient decision-making by the network business. For TNSPs this is codified in Chapter 6A of the Rules, and is implemented by the AER through the process of periodic revenue determinations.

3.8.3 Stakeholder views from first round consultation

Stakeholder submissions who supported the proposal noted that prudency reviews of capex are critical to ensuring that TNSPs do not ignore DM options.[67] It was also noted that there is a need for prudency reviews conducted by "relevant experts" until DM is better established.

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67 J. Goddard, Fuji Xerox Australia Pty Ltd, Investa Properties Ltd, Mudgee District Environment Group Inc, Inghams Enterprises Pty Ltd, CVC Limited, Stormlight Consulting Pty Ltd, Energetics Pty Ltd., ATA and Griffith.

The range of submissions[68] that did not support the proposal noted the following issues:

- the current ex-ante approach has been successful and that prudential reviews of capex are not required;[69]
- NSPs are the appropriate "experts" when assessing the efficient level of DM investment;[70]
- given the recent consideration of the ACCC and the AEMC of prudential reviews of capital expenditure, it would be inconsistent with those previous decisions to introduce prudential reviews of capital expenditure. Further analysis would be required to support such a change.[71]

3.8.4 Commission's assessment and reasoning

The Commission notes that the existing framework provides two key elements that seek to ensure that TNSPs undertake prudent expenditure. The obligations in relation to planning and the economic incentives regime.

With respect to network planning, the Rules provide a number of obligations to ensure that TNSPs appropriately consider non-network alternatives (including demand-side options). These requirements include a need to undertake consultation on proposals and the application of the Regulatory Test to ensure the option(s) chosen are efficient.

The existing ex-ante approach specifically encourages costs to be minimised as it provides clarity to business regarding the basis for which the regulatory asset base will be revalued and balances the risks of investment. These, in effect, provide more certainty for long term investment, and therefore implies a lower overall cost of capital.

Introducing an ex-post review of revenue can undermine the incentives provided in the ex-ante regime, by creating addition regulatory risk, and potentially increases the total costs to consumers. This is because network owners will factor in the possible ex-post decisions of a regulator rather than just the incentives inherent in the ex-ante regime. On that basis, and combined with the use of detailed planning obligations, the Commission considers that an ex-post review of expenditure for DM would substantially reduce the incentive properties of the current regime and could potentially increase perceptions of regulatory risk. The Commission, therefore has not accepted this proposal in the draft Rule.

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68 Energex, NGF, ENA, ERAA, ETNOF and TRUenergy.

69 ENA.

70 Energex, ENA.

71 TRUenergy, ETNOF.

3.9 Wholesale markets - including a mechanism for setting the price of demand side response activities

3.9.1 TEC proposal

The TEC considers that there is an absence of firm short or long-term prices for DM in the wholesale electricity market. The TEC noted that the absence of an appropriate mechanism is inhibiting the development of a mature DM aggregation market, which could provide extensive network support, facilitate greater efficiency and therefore reduce costs for consumers.

The TEC also proposed a new market design principle for the wholesale market to achieve the maximum level of efficient DM when dispatching the market to meet demand. The TEC considers that the investigation and implementation of DM should be an underlying principle and good practice to achieve maximum efficiency in meeting electricity demand. It did not consider DM to be a technology and hence its proposal did not breach the market design principles of avoiding special treatment of different technologies. In its proposal, the TEC did not provide any further reasoning for introducing this new market design principle.

3.9.2 Existing arrangements

Under the existing regime, there are two ways that DM providers can participate in the wholesale market. Firstly, by registering with NEMMCO as a scheduled load and bidding their scheduled load into the wholesale market. Secondly, to directly contract their services with Market Customers, e.g. retailers.

The design of the wholesale market is such that scheduled generators and scheduled loads comply with the five-minute dispatch schedule, a range of technical requirements to maintain and ensure system security and the spot price for each thirty-minute trading interval (determined by averaging the six preceding five-minute dispatch interval prices within that trading interval).

Clause 3.1.4 of the Rules sets out the NEM's market design principles. These principles relate to the operation of the wholesale market including its transparency and equal-access regime, and NEMMCO's role. Section 7 of the NEL provides for the overarching objectives for the operation of the national electricity market, including for the efficient use of electricity.

3.9.3 Stakeholder views from first round consultation

A number of submissions[72] agreed with TEC's proposal for promoting greater demand-side participation in the wholesale market as setting a price for DM would encourage greater investment in and facilitate growth of DM aggregation as a

[72] J. Goddard, Fuji Xerox Australia Pty Ltd, Investa Properties Ltd, Mudgee District Environment Group Inc, Inghams Enterprises Pty Ltd, CVC Limited, Stormlight Consulting Pty Ltd and Energetics Pty Ltd.

marketcommodity. However, other submissions[73] suggested that the use of scheduled loads already provided a demand-side bidding mechanism and that there were already appropriate arrangements for retailers to contract demand-side response. Some stakeholders[74] also considered that the proposal required further development and that these matters would be more appropriately considered in the context of the AEMC DSP Review.

Stakeholders[75] also considered that the proposed new market design principle contradicted the technology neutral market design principle. One submission[76] stated that the scope of the proposed new market design principle covering the efficiency of the use of electricity was too significant a change for consideration in a Rule change and would likely require an AEMC review for its proper consideration.

3.9.4 Commission's assessment and reasoning

The Commission considers that introducing a new mechanism that sets a price for demand management providers is a substantial change from the current spot price market design. To assess the merits of such a change, it is important to understand the detail of the proposal, how it would be implemented, and what the consequential impacts on the market would be. The TEC proposal does not provide any details on what the nature of such a mechanism and how it may be implemented. Given this proposal would be a significant change to the current market design, the lack of specific detail makes it difficult to assess adequately its merits in the context of this Rule change proposal.

Noting this, the broader question of what barriers currently exist for demand management providers wishing to participate in the wholesale market is currently under consideration in the context of the AEMC's DSP Review. Aspects related to DM are also being considered in the wider Review of Energy Market Frameworks in light of Climate Change Policies.

With respect to including a market design principle for demand management in Clause 3.1.4 of the Rules, the Commission considers that such a proposal would be inconsistent with existing technology neutral and equal-access design principles. [77] The current operation of the wholesale market does not preclude the use of demand management, if that is the most efficient option. DM options should be considered on their relative merits in relation to any other alternative.

The AEMC may only make a Rule if it is satisfied that the Rule will or is likely to contribute to the achievement of the National Electricity Objective[78]. This includes

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[73] TRUenergy, NGF, Energex, ERAA.

[74] NEMMCO, ETNOF, VENCorp.

[75] TRUenergy, NGF.

[76] TRUenergy.

[77] Clause 3.1.4 (a)(3) and Clause 3.1.4 (a) (5)

[78] Section 7, NEL.

the rules for operating the wholesale market, including the market design principles. It would be redundant to have a specific principle on efficient use when that is an overarching objective of the electricity market as a whole.

Based on this analysis, the Commission has determined not to accept this Rule change for the draft Rule.

A List of Stakeholder Submissions

- Alternative Technology Association
- Alternative Technology Association (ATA) - Supplementary Submission
- Citipower and Powercor
- Cool Nrg International
- CVC Limited
- Electricity Transmission Network Owners
- Energetics
- Energex
- Energy Networks Association
- Energy Response
- Energy Retailers Association Of Australia
- Ergon Energy
- ESAA
- ETSA Utilities
- Fuji Xerox
- GridX Power
- Griffith University
- Ingham Enterprises
- Investa Properties Limited
- John Goddard & Associates
- Mudgee District Environment Group
- National Generators Forum
- NEMMCO
- NEMMCO Additional Submission
- Next Energy

- NSW Minister For Energy
- SP Ausnet
- Stormlight Consulting
- TRUenergy
- VENCorp