



Australian Energy Market Commission

DRAFT RULE DETERMINATION

NATIONAL ELECTRICITY AMENDMENT (DEMAND MANAGEMENT INCENTIVE SCHEME AND INNOVATION ALLOWANCE FOR TNSPS) RULE 2019

PROPONENT

Energy Networks Australia

12 SEPTEMBER 2019

RULE

INQUIRIES

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

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

Reference: ERC0266

CITATION

AEMC, Demand management incentive scheme and innovation allowance for TNSPs, Draft rule determination, 12 September 2019

ABOUT THE AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

This work is copyright. The Copyright Act 1968 permits fair dealing for study, research, news reporting, criticism and review. Selected passages, tables or diagrams may be reproduced for such purposes provided acknowledgement of the source is included.

EXECUTIVE SUMMARY

- 1 Energy Networks Australia (ENA) submitted a rule change request proposing amendments to the National Electricity Rules (NER or rules) that would require the Australian Energy Regulator (AER) to develop a demand management incentive scheme (DMIS) and demand management innovation allowance mechanism (DMIA) to apply to transmission network service providers.
- 2 The DMIS provides for incentive payments to undertake efficient expenditure on non-network options. The DMIA provides funding for research and development (R&D) on demand management projects that have the potential to reduce long term network costs.
- 3 The Commission's draft rule determination is to make a more preferable draft rule to apply the DMIA, and not the DMIS, to transmission network service providers.
- 4 Stakeholder submissions received by the Commission strongly support efficient demand management solutions that reduce the need for investment in transmission and distribution infrastructure. However, most submissions questioned the benefits to consumers of introducing both the DMIA and DMIS, and were not convinced that the DMIA and DMIS are the best mechanisms to incentivise efficient non-network solutions.
- 5 In the Commission's view, introducing a DMIA for transmission is expected to encourage transmission businesses to expand and share their knowledge and understanding of innovative demand management projects that have the potential to reduce long term network costs and, consequently, could lower prices for consumers. Such innovation may play an important role in the transformation of the energy sector. The AER is expected to socialise network approaches and learnings by publishing DMIA reports for each transmission business on its website, as it does for distribution.
- 6 R&D can deliver overall benefits to consumers in the long term, but lead to higher costs in the short term. The nature of the regulatory control period imposed on networks, which 'resets' prices every five years or so, impacts the expected payoff of R&D projects. The DMIA addresses this issue under the regulatory framework.
- 7 The draft rule provides the AER with discretion as to whether and how to apply the DMIA, including the level of the innovation allowance – consistent with ENA's proposal. Enabling the AER to apply the DMIA improves the flexibility and responsiveness of the regime to changing technologies and market developments.
- 8 On the other hand, the Commission is not satisfied the DMIS promotes the long term interests of consumers. It is not clear from the evidence presented by ENA that the incremental benefits of introducing a DMIS are likely to outweigh the upfront costs to consumers. For example, if the DMIS is implemented, transmission businesses will receive incentive payments for undertaking non-network options that they already would have been required by the regulatory investment test for transmission (RIT-T) to adopt. This is a significant risk given transmission businesses appear to be increasingly utilising demand management solutions.

- 9 The Commission accepts ENA's view that networks may face upfront, transitional costs to develop their ability to utilise non-network options. But, ongoing incentive payments to transmission businesses are not necessary to overcome implementation barriers. These mostly one-off costs can be funded through AER revenue allowances. Other sources of funding may be available too – such as from ARENA or the DMIA (if implemented for transmission).
- 10 The Commission invites submissions on this draft rule determination, including the more preferable draft rule, by 24 October 2019. Following consideration of submissions, the Commission intends to publish its final determination by 5 December 2019.

CONTENTS

1	ENA's rule change request	1
1.1	The rule change request	1
1.2	Current arrangements	1
1.3	Rationale for the rule change request	1
1.4	Solution proposed in the rule change request	3
1.5	Relevant background	3
1.6	The rule making process	4
1.7	Consultation on draft rule determination	5
2	Draft rule determination	6
2.1	The Commission's draft rule determination	6
2.2	Rule making test	7
2.3	Assessment framework	9
2.4	Summary of reasons	10
3	Issues raised and Commission's conclusions	13
3.1	The DMIS could increase costs to consumers without clear benefits	13
3.2	ENA proposal objectives can be achieved through innovation allowance	26
	Abbreviations	31
	APPENDICES	
A	Legal requirements under the NEL	32
A.1	Draft rule determination	32
A.2	Power to make the rule	32
A.3	Additional rule making test – Northern Territory	32
A.4	Revenue and pricing principles	33
A.5	More preferable rule	33
A.6	Commission's considerations	33
A.7	Civil penalties	34
A.8	Conduct provisions	34

1 ENA'S RULE CHANGE REQUEST

1.1 The rule change request

Energy Networks Australia (ENA) submitted a rule change request proposing amendments to the National Electricity Rules (NER or rules) that would require the Australian Energy Regulator (AER) to develop a demand management incentive scheme (DMIS) and demand management innovation allowance mechanism (DMIA) to apply to transmission network service providers.¹

The DMIS provides for incentive payments to undertake efficient expenditure on non-network options. The DMIA provides funding for research and development (R&D) on demand management projects that have the potential to reduce long term network costs.

1.2 Current arrangements

Under the current rules, the DMIS and DMIA are only available for distribution network service providers. ENA proposes to apply the same approach to transmission, including giving the AER discretion as to whether to apply the schemes, and in determining the level of both incentives and the allowance.²

The AER is required under the NER to develop and publish the DMIS and DMIA schemes for distribution, consistent with the following respective objectives:

- provide distributors with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management (DMIS)³
- provide distributors with funding for research and development in demand management projects that have the potential to reduce long term network costs (DMIA).⁴

The AER published the DMIS and DMIA in December 2017 and has since begun applying the two schemes.

1.3 Rationale for the rule change request

ENA submits that the proposed rule change would promote innovation and create positive incentives for transmission businesses to undertake demand management approaches, which would benefit customers through lower transmission network and total system costs.⁵

Electricity network demand management generally helps to remove or reduce network constraints and investment, which potentially provides a less costly alternative to capital investment. Transmission businesses may be able to shift or reduce net demand on their network by, for example, providing financial incentives to encourage behavioural change or

1 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February 2019.

2 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February 2019, p. 3.

3 See NER clause 6.6.3.

4 See NER clause 6.6.3A.

5 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February 2019, p. 3.

contracting for local generation support. Lower total system costs mean lower electricity prices for consumers, all other things being equal.

ENA submits that the key driver for the proposed introduction of a DMIS for transmission is the current lack of positive financial incentives for the adoption of potentially lower cost non-network operating expenditure solutions. ENA considers there are 'practical implementation barriers' associated with putting in place a non-network solution – such as reputational and compliance risks, particularly when the market for non-network solutions is still developing. ENA considers that this potentially creates unbalanced incentives and a bias towards network capital investment under the current rules.⁶

ENA submits that the current regulatory framework does not provide certainty that any expenditure on research and development (R&D) to further develop efficient long-term non-network solutions will be able to be recovered by the transmission business. ENA states the framework provides a disincentive to incur expenditure on R&D because any expenditure results in an immediate increase in operating expenditure (opex), which is not necessarily offset by a decrease in either opex or capital expenditure (capex) in the same regulatory period.⁷

ENA says an increase in the take-up of non-network alternatives by transmission businesses, and in research to establishing the viability and commercialisation of innovative new non-network solutions, will assist the development of the non-network industry more broadly and increase confidence in non-network solutions. This in turn, ENA says, can be expected to result in a 'broadening and deepening' of the market for non-network services, which currently remains in its relative infancy: 'This will bring benefits to other potential users of non-network services, including AEMO in its capacity as market operator in managing system stability and ensuring reliability.'⁸ Further, ENA submits:⁹

The AEMC expects that the wholesale demand response mechanism and the ability for demand response aggregators to gain access to the wholesale electricity spot price will be completed by the end of this year. There may be some time allowed for underlying procedures and systems to be developed, before market commencement. Energy Networks Australia considers that this rule change will facilitate TNSPs partnering with these new market participants to develop and build scale solutions to meet identified transmission needs, including developing the hierarchy of use across the value chain as these new providers seek to develop the services market.

Consumers would ultimately fund the allowances under the DMIS and DMIA. These payments increase total allowed revenue, which in turn means higher network charges for consumers in

6 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February 2019, pp. 8–10.

7 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February 2019, p. 8.

8 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February 2019, pp. 20–21.

9 ENA submission to AEMC Consultation paper, 11 July 2019, p. 4.

the short term. ENA considers that these costs would be outweighed by longer-term cost savings for consumers as a result of more efficient expenditure.

1.4 Solution proposed in the rule change request

ENA proposes to amend existing clauses and include new clauses in Chapter 6A of the NER, as well as amending clauses in Chapter 11 (Savings and transitional rules), as follows:¹⁰

- Chapter 6A (economic regulation of transmission services) would be amended to add in the relevant objectives and principles for the DMIS and DMIA, consistent with the objective and principles set out in 6.6.3 and 6.6.3A of Chapter 6 (economic regulation of distribution services).
 - Consequent amendments would also be required to 6A.5.4(a)(5) and 6A.5.4(b)(5), which relate to a description of the building blocks.
- Either Part ZZZH of Chapter 11 (Savings and transition) would be amended, or a new Part added to Chapter 11 to allow TNSPs to apply to the AER for early application of the DMIS, ahead of their next regulatory determination, consistent with the rules contained in the National Electricity Amendment (implementation of demand management incentive scheme) Rule 2018 No.3.

1.5 Relevant background

The AER sets revenue and financial incentives for network businesses over a forward-looking period – usually five years. The allowed revenue is the basis for network charges, which are a component of electricity retailer bills. Network charges represent around 30 to 40 per cent of the average residential bill.¹¹

The AER must take into account the price, quality, safety, reliability and security of supply of energy.¹² In addition, the AER must consider the revenue and pricing principles under the NEL, which support the NEO.

Key aspects of the revenue and pricing principles are that regulated network service providers should be provided with:

- a reasonable opportunity to recover at least their efficient costs of providing network services and complying with regulatory obligations
- effective incentives to promote economic efficiency.¹³

The NER require the AER to use the building blocks approach to determine how much revenue a network business needs to cover its 'efficient costs' over the coming regulatory period. The AER uses the building blocks approach to forecast and lock-in the total revenue that an efficient and prudent business would require. In doing so, the AER takes into account

¹⁰ ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February 2019, p. 23.

¹¹ AER, State of the Energy Market 2018, p. 36.

¹² See NEL Section 7.

¹³ See NEL Section 7A.

expected demand and cost inputs, all applicable regulatory obligations or requirements on the business, and the reliability, security and safety of the network (among other things).¹⁴

Under the incentive-based regulatory framework, the AER sets an ex-ante revenue allowance and the network businesses are expected to attempt to outperform it. Networks that allow their efficiency to deteriorate earn lower profits. Networks that improve their efficiency are rewarded with higher profits – they are allowed to keep a proportion of the difference between their approved forecasts and their actual expenditure.

The AER applies various incentive schemes, such as the efficiency benefit sharing scheme (EBSS), capital efficiency sharing scheme (CESS) and service target performance incentive scheme (STPIS), to provide networks with a continuous incentive to improve their efficiency in supplying electricity services – while maintaining or improving service standards. The EBSS and CESS share operating and capital efficiency gains, respectively, between networks and consumers on historically a 30:70 basis. That is, the network businesses retain roughly 30 per cent of the efficiency gain (in NPV terms), while consumers retain about 70 per cent of the savings.

To discourage networks from cutting costs by reducing service levels the AER applies a STPIS, which rewards or penalises networks for their outage performance and, in the case of transmission network service providers, for the level of network constraints. This supplements the planning standard obligations in state legislation (where applicable).

Transmission businesses must already apply a regulatory investment test for transmission (RIT-T) prior to making significant network investments.¹⁵ The purpose of the RIT-T is to identify the transmission investment option that maximises net economic benefits and, where applicable, meets the relevant jurisdictional or electricity rule based reliability standards. Under the NER, in applying the RIT-T, a transmission business must consider all options that could reasonably be classified as 'credible options', including non-network solutions.¹⁶

1.6 The rule making process

On 23 May 2019, the Commission published a notice advising of its commencement of the rule making process and consultation in respect of the rule change request. A consultation paper identifying specific issues for consultation was also published. Submissions closed on 11 July 2019.

The Commission received 11 submissions as part of the first round of consultation.¹⁷ The Commission considered all issues raised by stakeholders in submissions. Issues raised in submissions are discussed and responded to throughout this draft rule determination. These issues are discussed and responded to in the relevant section of this draft rule determination.

¹⁴ See NER Part C of Chapter 6 and Part C of Chapter 6A.

¹⁵ See NER clause 5.15 and 5.16.

¹⁶ See NER clause 5.15.2.

¹⁷ Submissions were received from: AER, AGL, Australian Energy Council, EnergyAustralia, Energy Consumers Australia, Energy Efficiency Council, Energy Networks Australia (the proponent), ENGIE, Mondo, PIAC, and Government of South Australia.

1.7 Consultation on draft rule determination

The Commission invites submissions on this draft rule determination, including the more preferable draft rule, by 24 October 2019. Following consideration of submissions, the Commission intends to publish its final determination by 5 December 2019.

If any stakeholder wants to discuss aspects of this draft determination, please do not hesitate to contact Anthony Bell, Technical Specialist, at: Anthony.Bell@aemc.gov.au to request a meeting.

Any person or body may request that the Commission hold a hearing in relation to the draft rule determination. Any request for a hearing must be made in writing and must be received by the Commission no later than 19 September 2019.

Submissions and requests for a hearing should quote project number ERC0266 and may be lodged online at www.aemc.gov.au.

2 DRAFT RULE DETERMINATION

2.1 The Commission's draft rule determination

The Commission's draft rule determination is to make a more preferable draft rule. The more preferable draft rule is to apply the DMIA, and not the DMIS, to transmission network service providers. A copy of the more preferable draft rule is published with this draft rule determination.

The key features of the more preferable draft rule are:

- The AER must develop a demand management innovation allowance mechanism for transmission network service providers consistent with the demand management innovation allowance objective.¹⁸
- The objective of the demand management innovation allowance mechanism is to provide Transmission Network Service Providers with funding for research and development in demand management projects that have the potential to reduce long term network costs.¹⁹
- In developing and applying the mechanism, the AER must take into account the following:
 - the mechanism must be applied in a manner that contributes to the achievement of the demand management innovation allowance objective²⁰
 - demand management projects should have the potential to manage ongoing changes in demand²¹ and be innovative and not be otherwise efficient and prudent non-network options that a transmission network service provider should have provided for in its revenue proposal²²
 - the level of the allowance should be reasonable considering the long term benefit to retail customers, should only provide funding that is not available from any other source, and may vary by transmission network service provider and over time²³
 - the demand management innovation allowance may fund demand management projects which occur over a longer period than a regulatory control period.²⁴
- Any demand management innovation allowance mechanism developed and applied by the AER must require transmission network service providers to publish reports on the nature and results of demand management projects that are the subject of the allowance.²⁵

18 See clause 6A.7.6(a) of the Amending Rule.

19 See clause 6A.7.6(b) of the Amending Rule.

20 See clause 6A.7.6(c)(1) of the Amending Rule.

21 This differs to the corresponding clause for distribution, which says 'demand management projects should have the potential to *deliver ongoing reductions in demand or peak demand...*' The broader reference to '*manage ongoing changes in demand*' better accommodates possible network projects to address issues arising from the growth of solar PV exports and falling minimum demand.

22 See clause 6A.7.6(c)(2) of the Amending Rule.

23 See clause 6A.7.6(c)(3) of the Amending Rule.

24 See clause 6A.7.6(c)(4) of the Amending Rule.

25 See clause 6A.7.6(d) of the Amending Rule.

- The AER must develop and publish the demand management innovation allowance mechanism in accordance with the transmission consultation procedures by 31 March 2021.²⁶
- There are also a number of amendments to existing clauses in chapter 6A of the NEL to accommodate the demand management innovation allowance mechanism throughout the revenue determination process.²⁷

2.2 Rule making test

2.2.1 Achieving the NEO

Under the NEL the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the national electricity objective (NEO).²⁸ This is the decision making framework that the Commission must apply.

The NEO is:²⁹

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.

2.2.2 Making a more preferable rule

Under s. 91A of the NEL, the Commission may make a rule that is different (including materially different) to a proposed rule (a more preferable rule) if it is satisfied that, having regard to the issue or issues raised in the rule change request, the more preferable rule will, or is likely to, better contribute to the achievement of the NEO.

In this instance, the Commission has made a more preferable rule. The reasons are summarised below.

2.2.3 Revenue and pricing principles

In addition to having regard to the NEO, the Commission must take into account the revenue and pricing principles when making a rule for or with respect to transmission system revenue and pricing.³⁰

In making this draft determination, the Commission has considered the following aspects of transmission system revenue and pricing to be most relevant:

²⁶ See clause 6A.7.6(e) and the transitional rule of the Amending Rule.

²⁷ See amendments to clauses 6A.4.2, 6A.5.4, 6A.6.6, 6A.6.7, 6A.8.2, 6A.10.1A, 6A.14.1, 6A.17.1 and S6A.1.3 of the Amending Rule.

²⁸ Section 88 of the NEL.

²⁹ Section 7 of thence.

³⁰ Refer to section 88B of the NEL and Items 15 to 24 of Schedule 1 to the NEL.

- 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.³¹
- 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.³²

As the more preferable draft rule relates to such matters, the Commission must take into account the revenue and pricing principles. The revenue and pricing principles are set out in section 7A of the NEL.³³ The Commission considers the following revenue and pricing principles are the most relevant to the draft rule:

- A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes:
 - efficient investment in a distribution system or transmission system with which the operator provides direct control network services
 - the efficient provision of electricity network services
 - the efficient use of the distribution system or transmission system with which the operator provides direct control network services.
- Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.
- Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services.

In making this draft determination, including the more preferable draft rule, the Commission has taken the revenue and pricing principles into account.

The draft rule enables the DMIA for transmission, which is expected to create effective incentives over multiple regulatory control periods for network businesses to undertake R&D on demand management projects – promoting economic efficiency. Electricity network demand management generally helps to remove or reduce network constraints and investment. Innovations that increase the viability of non-network solutions potentially provide a less costly alternative to capital investment and could lead to improved utilisation of the transmission system by, for example, shifting or reducing net demand on the network.

2.2.4

Northern territory

The NER, as amended from time to time, apply in the Northern Territory, subject to derogations set out in regulations made under the Northern Territory legislation adopting the

31 Item 15 of Schedule 1 to the NEL.

32 Item 17 of Schedule 1 to the NEL.

33 Section 7A of the NEL.

NEL.³⁴ Under those regulations, only certain parts of the NEL have been adopted in the Northern Territory.³⁵

As the Commission has determined to make a more preferable draft rule which relates to parts of the NEL that apply in the Northern Territory,³⁶ the Commission is required to consider whether to make a uniform rule or differential rule under Northern Territory legislation.

Under the NT Act, the Commission may make a differential rule if, having regard to any relevant MCE statement of policy principles, a differential rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule.³⁷

A differential rule is a rule that:

- varies in its terms as between:
 - the national electricity system, and
 - one or more, or all, of the local electricity systems, or
- does not have effect with respect to one or more of those systems

but is not a jurisdictional derogation, participant derogation or rule that has effect with respect to an adoptive jurisdiction for the purpose of s. 91(8) of the NEL.

A uniform rule is a rule that does not vary in its terms between the national electricity system and the local electricity systems, and has effect with respect to all of those systems.³⁸

The Commission has determined to make a uniform rule as it does not consider that a differential rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule.

Further details of the legal requirements for making this more preferable draft rule are set out in Appendix A.

2.3 Assessment framework

Investing in and operating the networks in the long term interests of consumers means that network reliability, safety, security and quality requirements are met at efficient long term cost. This outcome will be achieved if a number of conditions are met:

- **Demand is met at lowest total system cost:** Incentive-based regulation provides incentives for transmission businesses to behave in a way that lowers overall total system costs which, over time, will lead to price and/or reliability, safety, security and quality benefits for consumers. In other words, the regulatory framework should promote efficient decision-making that encourages transmission businesses to identify and pursue

34 The regulations under the NT Act are the National Electricity (Northern Territory) (National Uniform Legislation) (Modifications) Regulations.

35 The version of the NEL that applies in the Northern Territory is available on the AEMC website.

36 While the draft rule principally amends Chapter 6A, which does not apply in the Northern Territory, it also makes minor amendments in Chapter 6 and Chapter 10 of the NEL, which do apply in the Northern Territory.

37 Section 14B of Schedule 1 to the NT Act, inserting section 88AA into the NEL as it applies in the Northern Territory.

38 Section 14 of Schedule 1 to the NT Act, inserting the definitions of "differential Rule" and "uniform Rule" into section 87 of the NEL as it applies in the Northern Territory.

the most efficient (or least cost) solution that can deliver the required level of supply reliability, irrespective of whether that solution is a network or non-network option.

- **Efficient investment in and use of assets takes place:** The incentives applied through the regulatory framework are an important determinant of how efficient transmission businesses invest in and maintain their infrastructure. The regulatory framework should therefore aim to enable:
 - use of existing assets to be optimised
 - the network to be managed to meet changing demand
 - assets to be replaced at the end of their useful life if it is necessary and efficient to do so.
- **Transmission businesses are able to recover efficient costs:** The regulatory framework should only allow for an efficient level of costs to be recovered by transmission businesses, rather than allowing an automatic pass-through of all expenditure. This would promote efficient investment in transmission networks while allowing the businesses to recover the efficient costs of owning and operating their networks.
- **Efficiency and innovation are rewarded:** There should be a positive relationship between efficiency and reward, and the transmission businesses should be incentivised to make improvements in efficiency.

The Commission's assessment has considered the extent to which the amendments proposed by ENA in its rule change request enable the AER to design and apply a DMIS and DMIA that supports these above conditions and, therefore, which promotes the NEO.

The amendments have been assessed against the relevant counterfactual arrangement. In this case, the counterfactual is the existing provisions in Chapter 6A of the NER.

In considering the rule change request, the Commission has separately analysed the DMIS and DMIA.

2.4 Summary of reasons

The more preferable draft rule made by the Commission is attached to and published with this draft rule determination.

Having regard to the issues raised in the rule change request and during consultation, the Commission is satisfied that the more preferable draft rule to implement DMIA will, or is likely to, better contribute to the achievement of the NEO.

A range of views were expressed in submissions, but most stakeholders were not convinced of the benefits to consumers of introducing both the DMIA and DMIS. The Commission accepts ENA's view that networks may face upfront, transitional costs to develop their ability to utilise non-network options. But we disagree on the best mechanisms to incentivise efficient non-network solutions.

In the Commission's view, introducing a DMIA for transmission creates a source of potential funding for networks to overcome the 'practical implementation barriers' of non-network

alternatives and recover their efficient costs – in addition to the AER's approved revenue allowance and ARENA funded projects. Ongoing incentive payments to transmission businesses are not necessary to overcome implementation barriers.

Further, a DMIA for transmission is expected to encourage transmission businesses to expand and share their knowledge and understanding of innovative demand management projects that have the potential to reduce long term network costs and, consequently, could lower prices for consumers. Such innovation may play an important role in the transformation of the energy sector. The AER is expected to socialise network approaches and learnings by publishing DMIA reports for each transmission business on its website, as it does for distribution.

R&D can deliver overall benefits to consumers in the long term, but lead to higher costs in the short term. Regulated monopolies, like transmission businesses, inherently have less of an incentive to conduct R&D than competitive businesses. The nature of the regulatory control period imposed on networks, which 'resets' prices every five years or so, impacts the expected payoff of R&D projects. The DMIA addresses this issue under the regulatory framework.

The draft rule provides the AER with discretion as to whether and how to apply the DMIA, including the level of the innovation allowance – consistent with ENA's proposal. This will support the AER in developing and applying an innovation allowance that is consistent with its objective, while being flexible and adaptable to future developments in the market and regulatory arrangements.

On the other hand, the Commission is not satisfied the DMIS promotes the NEO for the following reasons:

- It is not clear from the evidence presented by ENA that the incremental benefits of introducing a DMIS are likely to outweigh the upfront costs to consumers.
- If the DMIS is implemented, transmission businesses will receive incentive payments for undertaking non-network options that they already would have been required by the RIT-T to adopt.
 - This is a significant risk given transmission businesses appear to be increasingly utilising demand management solutions, as highlighted by stakeholder submissions.
- Ongoing incentive payments are not necessary to manage initial costs to transmission businesses to 'unlock' non-network solutions.
 - These mostly one-off costs can be funded through AER revenue allowances. There is no 'incentive gap problem' under the current regulatory framework, as acknowledged by ENA.
 - Other sources of funding may be available too – such as from ARENA or the DMIA (if implemented for transmission).
- The Commission considers other possible benefits of the DMIS suggested by ENA do not outweigh the costs to customers:

- The DMIS is not the most effective and direct way to promote a 'broader and deeper' market for non-network alternatives. Regardless, such industry subsidies may create inefficient market distortions and, therefore, are not necessarily warranted.
- The proposed rule does not fundamentally address the potential risk of unbalanced incentives under the regulatory framework, which could bias investment decisions. This issue is being considered more broadly by the Commission as part of the *Economic regulatory framework review* – as supported by stakeholder submissions.
- 'Cultural barriers' may exist in transmission businesses which mean they are resistant to or slow to adopt less familiar demand management approaches. However, the Commission is more concerned about exacerbating a 'cost of service mentality' – whereby networks believe they should only act to lower costs to the benefit of consumers if there are specific financial rewards for doing so.
- On balance, the Commission's draft rule determination is to make a more preferable draft rule to apply the DMIA to transmission regulation, and not the proposed DMIS – as discussed in more detail below.

3 ISSUES RAISED AND COMMISSION'S CONCLUSIONS

This chapter details the issues raised by ENA in its rule change request, issues raised in stakeholder submissions, and the Commission's analysis and conclusions. Specifically:

- Section 3.1 sets out the Commission's view that there is a significant risk that the application of the DMIS in particular would lead to higher costs to consumers and therefore does not promote the NEO.
- Section 3.2 sets out how the DMIA may promote innovation and efficient uptake of non-network solutions, in the long term interests of consumers.

Submissions were received by the Commission from: the AER, AGL, Australian Energy Council (AEC), EnergyAustralia, Energy Consumers Australia (ECA), Energy Efficiency Council (EEC), ENA (the proponent), ENGIE, Mondo, Public Interest Advocacy Group (PIAC), and Government of South Australia.

3.1 The DMIS could increase costs to consumers without clear benefits

3.1.1 What is a 'practical implementation barrier'?

ENA's submission to the consultation paper states that rather than addressing an 'incentive gap problem' in the regulatory framework, its rule change addresses the absence of positive financial incentives for transmission businesses to adopt efficient non-network solutions to overcome 'practical hurdles' or 'practical implementation barriers'.³⁹

Based on the rule change proposal and submissions to the consultation paper, the Commission interprets practical hurdles/implementation barriers to include establishing contract terms and conditions with non-network service providers, implementing internal business and communication protocols, and reputational and compliance risks associated with relying on a third party to deliver services. Reputational factors may include providing prescribed transmission services in a reliable and safe way, and being identified as providing efficient delivery of these services. ENA's explanation of practical hurdles/implementation barriers supports this interpretation:⁴⁰

This rule change proposal will facilitate building up possible non-network solutions, contractual terms and vendors for consideration in a timelier manner in regulatory investment processes. This is preferred to starting from a minimal base today and expecting a contract at scale to be commercially, technically and operationally viable when needed.

TNSPs' investment decisions to deploy non-network solutions are affected by considerations such as contracting and compliance risk relating to licence and other legislative obligations (including reliability obligations), along with the reputational risk

39 ENA submission to AEMC Consultation paper, 11 July 2019, p. 2.

40 ENA submission to AEMC Consultation paper, 11 July 2019, p. 3.

that might arise from any non-compliance. As such it is important that TNSPs can build confidence with vendors that demand response has enough diversity, will be available when required and will be oversubscribed so that the required demand response can be achieved.

The mechanisms to enable demand response and notify customers or DNSPs all need to be worked through as do the commercial terms and conditions. It would not be prudent or efficient to contract at scale and expect the required response without first building up confidence with vendors, communications and engagement processes for response, technology viability, durability and scale. Building enough maturity in the market for non-network solutions is a focus of the proposed rule change.

In the Commission's view, these practical hurdles appear to be largely one-off costs or temporal. That is, once contracts and processes are established and trialled, the future costs of commissioning non-network option service providers would be lower and compliance risks largely mitigated.

This raises the question of whether ongoing incentive payments are necessary. Alternatively, the AER could provide direct funding for these initial 'investment' costs under the current regulatory framework, or other sources of funding may be available – such as from ARENA or the DMIA (if implemented for transmission).

Other ways to fund 'initial hurdles'

AER revenue determinations can account for networks' recovery of transactions costs, and the AER would consider the case for spending proposals to achieve dynamic efficiency gains that benefit consumers. In other words, the AER can and has funded network initiatives based on potential longer term savings to consumers.⁴¹ The Commission generally agrees with EnergyAustralia that the AER's assessment of expenditures should recognise economic benefits that span multiple regulatory periods – including the role of option value in economic evaluations – and that this value may be significant in the current environment.⁴²

ARENA currently provides financial assistance to projects that accelerate the transition of renewable energy technologies along the innovation chain, from research and development to demonstration and large-scale pre-commercial deployment activities. In particular, ARENA aims to fund a range of flexible capacity technologies and mechanisms – from energy storage to demand response. Recent and relevant ARENA funded projects include:

- Ausgrid's 'Power2U' project, which involves the establishment a \$4.1 million fund to help selected customers to permanently reduce their electricity use.⁴³
- AEMO and ARENA demand response trial to provide 200 megawatts of emergency reserves for extreme peaks – ARENA committed \$28.6 million in total to fund set-up and

41 For example, the AER considered a TransGrid proposed opex 'step change' of \$10.2 million for an increase in its 'demand management innovation allowance' – which was in addition to the demand management expenditure already included in TransGrid's 'base year opex'. (AER, TransGrid transmission determination 2015–18, Attachment 7 – Operating expenditure, p. 60.)

42 EnergyAustralia submission to AEMC Consultation paper, 11 July 2019, p. 3.

43 See: <https://arena.gov.au/projects/ausgrid-power2u/>

operational costs for the projects, with \$7.2 million to be matched by the NSW Government for NSW-based projects.⁴⁴

- United Energy demand response project, which will use voltage control devices installed at substations across its distribution network to deliver demand response.⁴⁵

The DMIA scheme applied by the AER for distribution encourages the networks to direct their R&D funding towards projects that will promote demand management. Projects are required to be innovative and have the potential to reduce long-term network costs, whereby a project either:

- is based on new or original concepts – for example, a new or original ways of building or developing capability and capacity to undertake, facilitate or utilise demand management
- involves technology or a technique not previously implemented in the relevant market, or
- is focussed on customers in a market segment that has not been exposed to the technology.⁴⁶

Projects that seek to increase the networks' flexibility to adopt non-network options could meet these above criteria, if applied to transmission.

3.1.2

Risk of net costs to consumers

A common theme in submissions is strong support for efficient demand management solutions that reduce the need for investment in transmission and distribution infrastructure. However, it is not clear from the evidence presented by ENA that the incremental benefits of introducing a DMIS are likely to outweigh the upfront costs to consumers – as questioned by some stakeholders. For example:

- The South Australian Government recognises the potential for efficient non-network solutions to provide benefits for consumers. However, it considers the ENA rule change request has not adequately established the case that applying the DMIS/DMIA for transmission networks is a preferred mechanism to incentivise efficient non-network solutions.⁴⁷
- ECA submits the simple adoption of the DMIS/DMIA rules for transmission networks is an inappropriate solution: these businesses acknowledge that their ability to directly affect the level of demand is severely limited, and ECA understands recent market testing of demand response at transmission scale has been disappointing.⁴⁸
- The AER states that the DMIS for distribution remains largely untested, so it is not in a position to conclude how effective the current DMIS or DMIA are in achieving their objectives.⁴⁹

44 See: <https://arena.gov.au/news/aemo-arena-demand-response/>

45 See: <https://arena.gov.au/projects/united-energy-distribution-demand-response/>

46 AER, Demand management innovation allowance mechanism: Electricity distribution network service providers, Explanatory statement, December 2017, p. 6.

47 Government of South Australia (Department of Energy and Mining) submission to AEMC Consultation paper, 12 July 2019, p. 1.

48 ECA submission to AEMC Consultation paper, 15 July 2019, p. 4.

49 AER submission to AEMC Consultation paper, 11 July 2019, p. 2.

In contrast, PIAC submits:⁵⁰

Strengthening the incentive for TNSPs to pursue non-network options through the DMIS should lead to further savings being passed through to consumers and help to prevent the continued growth of Regulated Asset Bases, delivering sustainably affordable electricity prices for consumers into the future.

In assessing the potential benefits of DMIS, the Commission considers the counterfactual is difficult to establish and there are scenarios where consumers would be worse off. Two examples are explored below to demonstrate the risk of net costs to consumers.

First, if the DMIS is extended to transmission as proposed, transmission businesses will receive incentive payments for undertaking non-network options that they already would have been required by the RIT-T to adopt. If the overall costs of a non-network solution (including any quantifiable costs of 'practical hurdles') are lower than a capital investment option, the transmission business is expected to adopt the non-network solution – as required by the RIT-T and/or incentivised by the ex ante regulatory framework (including the EBSS/CESS/STPIS). Under this scenario, consumers will not benefit from the DMIS. The incentive payments would transfer benefits from consumers to the transmission business, and potentially lead to higher consumer prices overall.

This is a significant risk given examples highlighted in submissions of transmission businesses already successfully utilising demand-management approaches:

- The South Australian Government submits there is evidence that existing incentives and mechanisms are supporting transmission businesses to investigate and implement non-network solutions such as generation, energy storage and demand response – citing Dalrymple Battery Project and Port Lincoln generation network support arrangements.⁵¹
- AEC highlights TransGrid procured 350 MW of demand management in 2007-08 in the Sydney-Newcastle-Wollongong area, enabling it to defer construction of the Western 500 kV Project for one year. Further, AEC submits TransGrid partnered with EnerNOC to deliver a demand management project involving more than 80 sites across metropolitan Sydney, which saw a reduction of peak demand for the summer of 2012-13 by a total of 48 MW.⁵²
- AGL highlights TransGrid recently successfully applied a non-network solution under the Powering Sydney's Future program, which it says infers introducing further incentive mechanisms for demand management may be unnecessary and could add additional costs for consumers.⁵³
- ENA submits that under TransGrid's Powering Sydney's Future project, a \$250m project was able to be economically deferred using non-network solutions.⁵⁴

50 PIAC submission to AEMC Consultation paper, 10 July 2019, p. 1.

51 Government of South Australia (Department of Energy and Mining) submission to AEMC Consultation paper, 12 July 2019, p. 1.

52 AEC submission to AEMC Consultation paper, 10 July 2019, pp. 2–3.

53 AGL submission to AEMC Consultation paper, 11 July 2019, p. 2.

54 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February 2019, p. 9.

Moreover, Mondo submits:⁵⁵

TNSPs are currently exploring numerous options for how best to respond to the energy transformation challenges. For example, TNSPs are already exploring options for utilising grid connected storage as a means of avoiding load shedding in the event of overloads, thereby delaying network augmentation. TNSPs are also keen to examine how battery storage can be utilised to provide load management services, as well as their potential to contribute system strength and frequency control capability. Another example of TNSP interest is in seeking to use various load management techniques to optimise the utilisation of existing interconnector capability.

TransGrid said it is actively developing the demand management market in response to the customer perception that transmission networks do not actively pursue non-network alternatives and that the process during a RIT-T can be seen as a 'tick box' exercise. TransGrid acknowledges this concern and states it is working hard to satisfy customers that a non-network solution will be pursued wherever feasible and efficient.⁵⁶

Second, consumers could benefit from transmission businesses utilising more efficient solutions that would not have otherwise been adopted. However, any benefits to consumers would be at least partly transferred to the networks through the incentive payments.

If the overall costs of a non-network solution (including 'practical hurdles') are higher than a capital investment option, but the transmission business is incentivised to adopt the non-network solution because of the DMIS payments, consumers will pay higher overall prices, at least in the short term.

Under this scenario, the DMIS could create an investment distortion that leads to an inefficient allocation of resources – depending on possible future efficiency savings.

Longer term, consumers could benefit from dynamic efficiencies such that the overall costs of the non-network option are significantly lower in the future – as the market develops and the transmission business overcomes the 'practical implementation barriers'.

However, these future benefits to consumers are somewhat speculative and, if realised, would at least be partly transferred to the networks through any ongoing DMIS payments. A risk with the DMIS is that consumers would potentially fund ongoing incentive payments to manage 'barriers' that have been already overcome.

Better ways to promote the developing market for non-network services

In support of ENA's view that the DMIS and DMIA will assist the development of the non-network industry more broadly, EnergyAustralia submits that networks may not adequately consider benefits across the whole value chain for electricity when making investment decisions – and therefore undervalue non-network solutions. EnergyAustralia suggests the

⁵⁵ Mondo submission to AEMC Consultation paper, 11 July 2019, p. 2.

⁵⁶ TransGrid, Revenue Proposal 2018-19–2022-23, January 2017, p. 46.

Commission should investigate the extent to which transmission networks overlook market-wide benefits in practice.⁵⁷

PIAC submits:⁵⁸

... we consider there is a role to build a large, diverse and readily accessed pool of DR throughout each NEM region (including directly contracting with customers or via an aggregator or retailer). By such “market building” procurement, the collective pool could be called on to meet other potential value streams of DR far more efficiently and reliably than the current arrangements that lack coordination between the possible value streams. This could build a greater pool of cost-effective resources for the future, expanding the range of options for future market design and system operation strategies.

In the Commission’s view, providing incentive payments through the DMIS to networks to pursue demand-side solutions would only indirectly promote a ‘broader and deeper’ market for non-network alternatives. ENA did not attempt to quantify these ‘trickle-down’ benefits to consumers in its rule change request.

This objective would be more effectively achieved through an innovation allowance, such as the DMIA or ARENA funded projects, or possibly direct government subsidies (for example, by providing discounted financing costs for new start-ups). Any such government policy would be based on a deep market analysis to justify intervention.

In any case, imposing advantages for certain market competitors through subsidies, especially in the absence of clearly identified positive externalities, may inefficiently distort investment signals and dull competitive pressures. Regulation should not be about ‘picking winners’ – it is better to allow the market to ‘decide’ than for the regulator or the policy maker to favour a particular technology or solution and have customers carry the risk.⁵⁹

Are consumers willing to fund this investment?

ENA has positioned consumers or end customers to be the main beneficiary of the DMIS. However, ENA did not provide evidence that consumers are willing to accept higher upfront charges to fund the proposed incentive payments to networks – with the prospect of at least lower future network charges as non-network options become more readily available and implementable.

The AER submits there needs to be evidence of consumer support for extending the DMIS (and DMIA) to transmission, noting consumer support was a key factor in the introduction and design of the distribution schemes.⁶⁰

The AER states:⁶¹

57 EnergyAustralia submission to AEMC Consultation paper, 11 July 2019, p. 1.

58 PIAC submission to AEMC Consultation paper, 10 July 2019, p. 2.

59 See: <https://www.aer.gov.au/news/networks-must-deliver-better-outcomes-for-consumers/perspectives-on-regulation-in-a-changing-environment-what-does-%E2%80%98success%E2%80%99-look-like-in-energy-regulation>

60 AER submission to AEMC Consultation paper, 11 July 2019, pp. 2–3.

61 AER submission to AEMC Consultation paper, 11 July 2019, p. 2.

A DMIS and DMIA rely on consumers funding incentive and allowance payments in the short term in the expectation of longer term benefits through improved take-up of efficient demand management options. For that reason, we consider consumer support for this rule change request is critical.

The Commission received two submissions from consumer representatives to the May 2019 consultation paper. PIAC 'supports the intent of the rule change',⁶² while ECA does not.⁶³

On the one hand, we are currently assessing a range of propositions emerging from the Integrated System Plan (ISP) and other processes purporting to make the case for more transmission network investment and that these are essential for reliability and security. On the other hand, we have this rule change proposal that implies there are opportunities to not make transmission investment that are being foregone but for the want of a positive incentive. Given this apparent conflict Energy Consumers Australia is taking a conservative approach – against change – in relation to all proposals related to transmission.

A lack of consumer support is not reason enough to reject a rule change request. However, it is a factor especially in circumstances where the proposal allocates risk to consumers. The Commission seeks further submissions by consumer representatives on this draft determination.

3.1.3

Does the rule change help to balance incentives under the regulatory framework?

The Commission has considered the extent to which the rule change request relates to the Commission's exploration of alternative models for network incentives and revenue-setting (eg, 'totex' approaches) to manage the risk of unbalanced incentives under the regulatory framework – as part of the *2019 Economic regulatory framework review*. This broader consideration is supported by stakeholders in several submissions.⁶⁴

ENA states that its rule change proposal addresses an imbalance of incentives that currently exists when pursuing demand management projects. It considers the lack of positive incentives for non-network options potentially creates a bias towards network capital investment under the current rules, and this has the potential to result in transmission businesses not having a sufficient incentive to undertake efficient non-network investment.⁶⁵

The Commission considers the rule change does not fundamentally address the risk of unbalanced incentives leading to capex bias.

62 PIAC submission to AEMC Consultation paper, 10 July 2019, p. 1.

63 ECA submission to AEMC Consultation paper, 15 July 2019.

64 Including submissions from AGL (pp. 1–2), EnergyAustralia (p. 1), ENGIE (p. 2) and Mondo (pp. 2–3). EnergyAustralia suggests exploration of further incentive issues and overseas models (p. 3), which the Commission will consider as part of the Economic regulatory framework review.

65 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February 2019, p. 26.

DMIS would not address the underlying cause of unbalanced incentives

'Practical implementation barriers' to take-up non-network options, as described by ENA, were not a significant factor in the Commission's finding in the *2018 Economic regulatory framework review* that the regulatory framework creates unbalanced incentives between capex and opex solutions. The Commission concluded that the misalignment of incentives is due largely to the current method of separate assessment and remuneration of opex and capex.⁶⁶

The Commission found the risk of unbalanced incentives may distort investment decisions where a network service provider may choose a solution that would provide the greatest financial returns instead of the most efficient solution.⁶⁷

Even if a totex framework applied under the regulatory framework, the 'practical hurdles' of non-network alternatives would still create additional 'investment' costs that would be weighed by the business against the total costs of an alternative capex solution. That is not a distortion. It is comparing the costs/risks of possible solutions to identify the least cost option overall.

A primary example of an inefficient distortion is when a network business prefers a capex solution because its expected cost of capital is lower than the regulated cost of capital, which means the capex solution would provide the greatest financial return – all other costs being equal between a network and non-network solution.

Stakeholder submissions came to a similar conclusion. For example, AEC submits:⁶⁸

Whilst the AEC encourages the use of DM alternatives, which can unequivocally deliver lower prices for consumers, the question of capex over opex bias in the investment decisions of transmission networks is not actually answered by DMIS arrangements. For these reasons we do not support the use of cost uplift for such projects.

AGL states:⁶⁹

... this rule change was proposed to address the issue that there is a bias towards investment in CAPEX projects instead of non-network options. While we support networks being encouraged to engage efficient non-network options, including demand management, we consider the AEMC should consider the issue more broadly. It would be more cost-effective to address the underlying problem related to incentives rather than introducing a specific incentive mechanism for demand management.

EnergyAustralia submits:⁷⁰

The ENA highlights potential barriers to pursuing non-network solutions however in

66 AEMC, 2018 Economic regulatory framework review, July 2018, p. 36.

67 AEMC, 2018 Economic regulatory framework review, July 2018, p. 34.

68 AEC submission to AEMC Consultation paper, 10 July 2019, pp. 1–2.

69 AGL submission to AEMC Consultation paper, 11 July 2019, pp. 1–2.

70 EnergyAustralia submission to AEMC Consultation paper, 11 July 2019, p. 3.

some cases these reflect imbalances between incentives for capital and operating expenditures. These imbalances would not be effectively addressed through demand management incentives.

ENGIE considers that the introduction of a DMIS/DMIA incentive scheme for transmission is not warranted purely on the basis of attempting to align capex and opex incentives.⁷¹

3.1.4

Cultural factors

In its rule change request, ENA both notes other stakeholder views that the DMIS would help to address the 'cultural barriers' within network businesses to assessing demand management, and references the Commission's *2018 Economic regulatory framework review* finding that cultural issues appear to contribute to a capex bias in certain circumstances.⁷²

The suggestion is that incentive payments (combined with profit maximising objectives) may promote positive change to network businesses' internal culture to be more flexible and innovative, which could have significant longer term benefits to consumers.

The DMIS may complement other recent initiatives to improve the culture of the sector, such as:

- Industry led awards recognise leadership in consumer engagement and innovation by network businesses. This has helped to build knowledge of successful engagement approaches, and created strong reputational incentives and rivalry among the businesses – driving innovation and experimentation.
- The Energy Charter, which seeks to progress the culture and solutions required to deliver a more affordable, sustainable and reliable energy system: "It is focused on embedding a customer-centric culture and conduct in energy businesses to create tangible improvements in affordability and service delivery."⁷³ Signatories are publicly accountable for delivering against its five underlying principles to provide improved outcomes for customers.

EnergyAustralia submits the Commission should explore the claim from ENA that networks have a 'cultural' bias against non-network solutions:⁷⁴

Knowing the root cause of this bias is important in designing an effective solution, and could be one or a combination of:

- unusual counter-party risk or the market for non-network services being immature
- a general reluctance of some TNSPs to partner with non-network service providers

71 ENGIE submission to AEMC Consultation paper, 20 June 2019, p. 3.

72 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February 2019, p. 9; 30.

73 The Energy Charter, January 2019, p. 1.

74 EnergyAustralia submission to AEMC Consultation paper, 11 July 2019, p. 3.

- poor valuation of non-network alternatives based on a cost of capital approach, rather than present value of avoided network costs over the life of the assets being deferred
- shortcomings in consultation processes that prevent proponents from being appropriately engaged (e.g. regulatory investment tests, transmission determinations etc).

Extrinsic motivations can negatively impact intrinsically motivated behaviours

ENA states transmission businesses receive no reward for implementing efficient non-network options.⁷⁵ At the same time, ENA says non-network solutions have an increasingly important role to play, and increased uptake of efficient non-network solutions is expected to benefit customers through lower transmission and total system costs.⁷⁶

The Commission is concerned that providing additional payments for networks through the DMIS to innovate and deliver efficient network services to the benefit of their customers could exacerbate a 'cost of service mentality', which negatively impacts dynamic efficiency and could hinder the market transition.

AEC submits providing additional financial incentives for transmission businesses to undertake demand-side investments means that future action will occur only when they are inefficiently generous, and this is not the best approach to address the cultural and commercial biases to invest in capex.⁷⁷

ENGIE submits the implication of ENA's proposal is that transmission businesses will hesitate to undertake non-network options, even when they are cheaper, because of their unfamiliarity with such options and therefore how they will work out. However, ENGIE says that under the current regulatory framework networks already have clear financial incentives to choose the cheaper option because they retain a share of the savings: 'It's not clear then, that an additional incentive is the best solution to such an issue.'⁷⁸

ECA submits:⁷⁹

In the current environment the biggest reputational risk to all NSPs is the perception that they have no separate interest in fulfilling the NEO and in particular in helping to reduce costs to consumers, but instead can only be expected to act in the interest of consumers in response to a specific identified financial incentive. The Proposal seems to reflect that position.

75 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February 2019, p. 26.

76 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February 2019, p. 3.

77 AEC submission to AEMC Consultation paper, 10 July 2019, p. 3.

78 ENGIE submission to AEMC Consultation paper, 20 June 2019, p. 2.

79 ECA submission to AEMC Consultation paper, 15 July 2019, p. 2.

What would be expected in a competitive environment?

The regulatory framework seeks to emulate workably competitive market outcomes and promote a competitive mindset/culture in networks to an extent. For example, the expectation is that network businesses should seek out new ways to improve operations and service quality to the benefit of consumers, rather than preferring a 'quiet life'. Although somewhat abstract, competitive-market outcomes provide a useful efficiency benchmark.

It is arguable that the practical hurdles/implementation barriers described by ENA are 'business-as-usual' costs that do not require separate, additional funding. Under the incentive-based regulatory framework, networks are expected to manage the inevitable 'ups and downs' in expenditure components from year-to-year (to the extent they do not offset each other) by continually re-prioritising their work programs – as would be expected in a competitive market. Non-network solutions offer the transmission businesses valuable options to manage change and respond to new challenges. This suggests both the DMIS *and* DMIA may not be warranted.

ENGIE submits:⁸⁰

Businesses under the pressure of competitive forces frequently have to adapt their operations in order to reduce their costs or improve their product or service. To the extent that they are trying out approaches that are new to them, this could be considered in the broadest sense "innovation" but is also a normal part of business.

Further, ENGIE argues the regulatory framework is not predicated on fully de-risking the networks – otherwise they could be financed on fully risk-free terms:⁸¹

Accordingly, the simple decision between a more familiar capex solution and a less familiar but potentially cheaper opex solution should not warrant an additional incentive.

3.1.5

Distribution vs transmission, and the impact of the RIT-T

Commencing 1 January 2008, chapter 6 of the NER included the demand management incentive scheme for distribution.

A 2007 rule change request by the Total Environment Centre proposed the development of a demand management incentive scheme for transmission (among other things).⁸² The Commission did not agree with the proposal. We considered a revenue cap provides strong incentives for the transmission businesses to minimise costs because a regulated business is able to earn larger profits by reducing costs, and demand management can be an effective way for them to reduce costs. Further, the Commission stated that in contrast to a price cap (which applied to distributors at the time), under a revenue cap the network is not exposed to the loss of revenue associated with a reduction in usage at peak time.⁸³

⁸⁰ ENGIE submission to AEMC Consultation paper, 20 June 2019, p. 2.

⁸¹ ENGIE submission to AEMC Consultation paper, 20 June 2019, pp. 2–3.

⁸² Total Environment Centre, Rule change proposal – demand management and transmission networks, 6 November 2007.

⁸³ AEMC, Demand Management, Rule Determination, April 2009, p. 32.

In 2015, the Commission made the *Demand management incentive scheme rule* in response to rule change requests submitted by the COAG Energy Council and the Total Environment Centre. This rule change made amendments to the existing demand management arrangements to:

- create separate provisions for a demand management incentive scheme and a demand management innovation allowance mechanism
- introduce an objective for the incentive scheme, and a separate objective for the innovation allowance.
- introduce a set of principles for the incentive scheme, and a separate set of principles for the innovation allowance, intended to guide the AER in developing and applying each of these to help achieve their respective objectives.
- require the AER to develop and publish the incentive scheme and innovation allowance in accordance with the distribution consultation procedures.⁸⁴

As part of the 2015 demand management incentive scheme rule change process, some stakeholders made submissions on whether the DMIS and DMIA should also be applied to transmission. The Commission found:

- transmission businesses could, and had, contributed to effective demand management – albeit in a more limited capacity compared to the demand side and distribution side
- transmission businesses were already required to consider the potential for demand management options (non-network options) under the RIT-T
- the AER could already provide funding for non-network solutions under the regulatory framework through the operating expenditure allowance (and had done so)
- ultimately, consideration of the application of the DMIS and DMIA for transmission network regulation was out of scope of the rule change proposal.⁸⁵

A greater proportion of projects are likely to be subject to the RIT in transmission compared to distribution, given the lumpier nature of transmission investments. The RIT-T rules and related AER guidelines promote consultation and consideration of all credible options to address an investment need – including a transparent process for non-network service providers to propose alternative solutions.

Transmission businesses are required to consult all registered participants, AEMO and interested parties on a RIT-T project – including preparation of a consultation report that outlines the technical characteristics of the identified need that a non-network option would be required to deliver.⁸⁶

A transmission business must apply the RIT-T to all proposed transmission investment except where a proposed investment is required to address an urgent and unforeseen network issue, or the estimated capital cost of the most expensive option to address the identified need is which is technically and economically feasible is less than \$6 million – among other factors.

⁸⁴ AEMC, Demand management incentive scheme, Rule Determination, August 2015, p. iii.

⁸⁵ AEMC, Demand management incentive scheme, Rule Determination, August 2015, pp. 27–28.

⁸⁶ NER clause 5.16.4(b).

Where a transmission business does not need to apply the RIT-T to a proposed investment, a transmission business must ensure, acting reasonably, that the investment is planned and developed at least cost over the life of the investment.⁸⁷

ENA submits the nature and scale of transmission projects means that, while the scale of non-network solutions required to address transmission-level network constraints may be more challenging than at the distribution-level, the potential benefit of deferred network investment is commensurately larger.⁸⁸ ENA says its rule change request is complementary to the RIT-T, as the application of the DMIS and DMIA could result in more non-network solutions being viable through the promotion of a more mature non-network solution market.⁸⁹

In response, ECA submits that if a transmission project is sufficiently large for the impact on prices to be material, the investment will need to satisfy the RIT-T.⁹⁰ Further:⁹¹

If there is a viable non-network solution, as is assumed in the case for the DMIS, then the network solution would not meet the requirements of the RIT-T and the TNSP would be required to implement the non-network solution to meet the requirements of their licence, which would seem to be incentive enough.

AEC says transmission networks are already required to consider non-network options and if they are failing to do so, the proposed rule change is not a prudent way to address this bias.⁹²

EnergyAustralia submits justification for applying demand management incentives to distributors may not apply to transmission because they face different circumstances – for example, the diversity of projects on distribution networks may mean that there are less individual commercial-scale demand management opportunities for distributors than transmission businesses.⁹³ In contrast, ENA says it is not aware of any evidence that non-network solutions are any less viable for transmission than distribution.⁹⁴

The Commission maintains that transmission businesses have a more limited ability or fewer opportunities to utilise demand management solutions, compared to distribution, due to the challenges presented by the large scale of transmission projects – as acknowledged by ENA above. We are closely monitoring the outcomes of the DMIS for distribution, which will inform the AER's ongoing application of the scheme.

The South Australian Government says the proposal has not fully explained why non-network solutions are not adequately incentivised through existing business practices, market

87 Clause 5.16.3(a)(2) of the NER states a figure of \$5 million, but the AER's latest cost threshold determination, conducted in accordance with clause 5.15.3 of the NER, has specified that a RIT-T applies where the capital cost exceeds \$6 million.

88 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February 2019, p. 9.

89 ENA submission to AEMC Consultation paper, 11 July 2019, p. 2.

90 ECA submission to AEMC Consultation paper, 15 July 2019, p. 2.

91 ECA submission to AEMC Consultation paper, 15 July 2019, p. 2.

92 AEC submission to AEMC Consultation paper, 10 July 2019, p. 3.

93 EnergyAustralia submission to AEMC Consultation paper, 11 July 2019, p. 4.

94 ENA submission to AEMC Consultation paper, 11 July 2019, p. 3.

mechanisms and trial support mechanisms – such as the RIT-T, Network Support and Control Ancillary Services and trial support mechanisms such as ARENA funding.⁹⁵ Further:⁹⁶

... the DMIS and DMIA were made in a period of broader reform to incentive (sic) non-network options for distribution networks. Changes included new requirements for network prices that reflect the efficient cost of providing network services to individual consumers, which are still in the process of being implemented. The Division notes that a significant driver of the AER applying DMIS and DMIA is to form a bridge to a framework more focussed on efficient pricing of distribution network services. This driver does not appear to exist for transmission network services, noting efficient prices have not been identified as an issue for transmission connected customers and for distribution connected customers the issue is addressed through the DMIS and DMIA. The view of the Australia Energy Regulator would be valuable on these specific issues.

3.2 ENA proposal objectives can be achieved through innovation allowance

A range of views were expressed in submissions, but most stakeholders were not convinced of the benefits to consumers of introducing both the DMIA and DMIS. The Commission accepts ENA's view that networks may face upfront, transitional costs to develop their ability to utilise non-network options. But we disagree on the best mechanisms to incentivise efficient non-network solutions.

Introducing a DMIA for transmission creates a source of potential funding for networks to overcome the 'practical implementation barriers' of non-network alternatives and recover their efficient costs – in addition to the AER's approved revenue allowance and ARENA funded projects. Ongoing incentive payments to transmission businesses are not necessary to overcome implementation barriers.

Further, the DMIA is expected to encourage transmission businesses to expand and share their knowledge and understanding of innovative demand management projects that have the potential to reduce long term network costs and so prices for consumers. R&D can deliver overall benefits to consumers in the long term.

Consistent with this view, EEC submits there appears to be a reasonable case for providing transmission businesses with a DMIA, but it is less clear if they already have good incentives to invest in demand management, or whether they will need access to a DMIS.⁹⁷ EnergyAustralia says a justification of the rule change, which essentially creates a subsidy, is to accelerate and enable demand management deployment – but any such subsidy should be time-limited and exist for the purposes of overcoming deployment barriers, such as high cost or risks to the network, rather than correcting incentive issues.⁹⁸

95 Government of South Australia (Department of Energy and Mining) submission to AEMC Consultation paper, 12 July 2019, p. 1.

96 Government of South Australia (Department of Energy and Mining) submission to AEMC Consultation paper, 12 July 2019, p. 1.

97 EEC submission to AEMC Consultation paper, 19 July 2019, p. 2.

98 EnergyAustralia submission to AEMC Consultation paper, 11 July 2019, p. 2.

3.2.1 Promoting innovation

Innovation can improve allocation of resources over time, which can in turn reduce long term costs. Innovation may also improve the ability of networks to adapt efficiently to changed economic conditions. Such dynamic efficiencies often involve a trade-off. R&D may lead to higher costs in the short run. But, without this investment and innovation, the network businesses may be unable to find progressively better ways of providing network services.

In its submission to the consultation paper, Mondo states:⁹⁹

The current rapid rate of transition which is being experienced in the energy sector has increased the need for industry participants to be innovative in their approach to problem solving. In the past, it was feasible for industry participants to take a cautious approach to change, and carefully examine any past examples as learning opportunities. The current paradigm however means that there are few if any past examples to provide learning opportunities, and participants are therefore required to take additional risks in implementing innovative solutions to new problems.

R&D requires investment costs to be incurred by the network business and the 'payoff' is generally uncertain. Regulated monopolies like network businesses arguably have less of an incentive to conduct R&D than competitive businesses. This is because networks face lower 'up-side risk' given they cannot by definition gain a 'competitive advantage'. Moreover, to the extent that R&D results in future cost reductions, networks will pass a material portion of these gains onto electricity consumers through incentive regulation. Additionally, networks still face 'down-side risk' – if R&D costs occur significantly before the benefits, the businesses risk being financially penalised from making these decisions under the EBSS and/or CESS. ENGIE submits:¹⁰⁰

To the extent that TNSPs need to carry out specific "research and development" activities (as opposed to merely being prepared to adapt to previously unfamiliar ways of doing business) in order to be able to substitute in non-network options for network options, then the case for some regulatory support is stronger. In Great Britain, where the CPI-X style regulatory framework has been applied for longer than in Australia, it was observed some time ago that the framework was good at driving efficiency, including certain types of innovation that typically resulted in a clear payoff over a short time frame, but inhibited research and development into longer-term issues where the chance of success of any given project was lower, and the network's opportunity to retain the benefits of success was curtailed.

The AER can fund R&D costs through the opex allowance, so there is not necessarily a gap in the current regulatory framework. Nevertheless, the Commission considers there are benefits to formalising this arrangement and for the AER to better socialise sector approaches and learnings – capturing the positive externalities of innovation. For the distribution DMIA, the

⁹⁹ Mondo submission to AEMC Consultation paper, 11 July 2019, p. 1.

¹⁰⁰ ENGIE submission to AEMC Consultation paper, 20 June 2019, p. 3.

AER publishes the network businesses compliance reports on its website as a 'one-stop-shop'¹⁰¹ to allow third parties to more easily compare and contrast options.¹⁰²

As stated by ENA:¹⁰³

The rule change proposal will provide a certain and robust reporting framework for demand management which will allow TNSPs to take a more proactive approach in innovation and research and pursue developments in this area. This will provide more visibility for consumers over how TNSPs are using these arrangements to lower total system costs through the specific information provided to and published by the AER.

PIAC considers that although the AER can approve 'innovation allowances' under the current regulatory framework (such as for TransGrid), a formal mechanism would be beneficial to all stakeholders by providing greater certainty to both the AER and networks in terms of the criteria innovation projects must meet in order to qualify. Further, PIAC says it would provide greater certainty that the lessons and insights from the innovation projects would be shared publicly.¹⁰⁴

3.2.2 Implementation of the DMIA to transmission

ENA proposes to apply the current distribution DMIA to transmission, including for the AER to have discretion in how it designs and applies the DMIA for transmission businesses.¹⁰⁵

No stakeholder submissions questioned the wording of the distribution DMIA rules or whether the AER should have significant discretion to apply the DMIA for transmission businesses, as proposed by ENA. However, submissions from AGL,¹⁰⁶ AEC,¹⁰⁷ EnergyAustralia,¹⁰⁸ the Energy Efficiency Council,¹⁰⁹ and ENGIE¹¹⁰ raised issues with how the schemes should be designed by the AER, and highlighted interrelationships with other regulatory mechanisms – especially ring-fencing guidelines for transmission. These issues are may be considered by the AER.

101 For example, see: <https://www.aer.gov.au/networks-pipelines/compliance-reporting/demand-management-innovation-allowance-dmia-assessment-2016-17-and-2017>

102 Clause 6.6.3A of the NER says: 'Any mechanism developed and applied by the AER must require Distribution Network Service Providers to publish reports on the nature and results of demand management projects the subject of the allowance.' To give effect to this, it appears the AER requires the distribution businesses to submit compliance reports to it in a form that is capable of being published by the AER – with the intention of then publishing the reports on its website to 'increase the usefulness and accessibility of each project report'. (AER, Demand management innovation allowance mechanism: Explanatory statement, December 2017, p. 26.) The Commission expects that AER would adopt a similar approach for transmission.

103 ENA submission to AEMC Consultation paper, 11 July 2019, p. 4.

104 PIAC submission to AEMC Consultation paper, 10 July 2019, p. 1.

105 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February 2019, p. 6.

106 AGL submission to AEMC Consultation paper, 11 July 2019, p. 3.

107 AEC submission to AEMC Consultation paper, 10 July 2019, p. 2; 4.

108 EnergyAustralia submission to AEMC Consultation paper, 11 July 2019, pp. 3–5.

109 EEC submission to AEMC Consultation paper, 19 July 2019, p. 2.

110 ENGIE submission to AEMC Consultation paper, 20 June 2019, pp. 3–4.

The AER submits that if a rule change is approved, it would require sufficient flexibility to consult on and develop a scheme and mechanism for transmission businesses, including its design, implementation timeframe, and application.¹¹¹ Further:¹¹²

We consider further analysis of the existing regulatory framework as it relates to TNSPs is necessary before the specific details of a DMIS and DMIA for TNSPs are determined. There should also be sufficient time allowed for consultation with stakeholders to evaluate the differences between DNSPs and TNSPs, and any implications for the design and application of a scheme and mechanism. This would also allow us time to gather data and learn more from the DMIS and DMIA for DNSPs.

ENA states the AER should be afforded enough time to develop and consult on the guidelines once the final rule is made. ENA agrees with the previous AER sentiment that DMIA should only be enabled at the start of the next regulatory control period.¹¹³

Given the need for the AER to develop and consult on the guidelines and to secure resources to fulfil this new function, the AER has indicated its preference to commence the rule change in the first quarter of 2021 in correspondence with the Commission. This would allow time for the DMIA to apply to the TransGrid, ElectraNet and Murraylink network revenue determinations. The Commission seeks stakeholder views on the requirement for the AER to develop and publish the DMIA by 31 March 2021.

Commission's draft determination to enable the DMIA for transmission

As detailed in section 2.1 of this draft determination, the more preferable draft rule introduces a DMIA mechanism to apply to transmission network service providers. The draft rule requires:

- The AER must develop a demand management innovation allowance mechanism for transmission network service providers consistent with the demand management innovation allowance objective.¹¹⁴
- The objective of the demand management innovation allowance mechanism is to provide Transmission Network Service Providers with funding for research and development in demand management projects that have the potential to reduce long term network costs.¹¹⁵
- In developing and applying the mechanism, the AER must take into account the following:
 - the mechanism must be applied in a manner that contributes to the achievement of the demand management innovation allowance objective¹¹⁶

111 AER submission to AEMC Consultation paper, 11 July 2019, p. 2.

112 AER submission to AEMC Consultation paper, 11 July 2019, p. 3.

113 ENA submission to AEMC Consultation paper, 11 July 2019, p. 4.

114 See clause 6A.7.6(a) of the Amending Rule.

115 See clause 6A.7.6(b) of the Amending Rule.

116 See clause 6A.7.6(c)(1) of the Amending Rule.

- demand management projects should have the potential to manage ongoing changes in demand¹¹⁷ and be innovative and not be otherwise efficient and prudent non-network options that a transmission network service provider should have provided for in its revenue proposal¹¹⁸
- the level of the allowance should be reasonable considering the long term benefit to retail customers, should only provide funding that is not available from any other source, and may vary by transmission network service provider and over time¹¹⁹
- the demand management innovation allowance may fund demand management projects which occur over a longer period than a regulatory control period.¹²⁰
- Any demand management innovation allowance mechanism developed and applied by the AER must require transmission network service providers to publish reports on the nature and results of demand management projects that are the subject of the allowance.¹²¹
- The AER must develop and publish the demand management innovation allowance mechanism in accordance with the transmission consultation procedures by 31 March 2021.¹²²
- There are also a number of amendments to existing clauses in chapter 6A of the NER to accommodate the demand management innovation allowance mechanism throughout the revenue determination process.¹²³

117 Again, this differs to the corresponding clause for distribution, which says 'demand management projects should have the potential to *deliver* ongoing *reductions in demand or peak demand*...' The broader reference to '*manage* ongoing *changes* in demand' better accommodates possible network projects to address issues arising from the growth of solar PV exports and falling minimum demand.

118 See clause 6A.7.6(c)(2) of the Amending Rule.

119 See clause 6A.7.6(c)(3) of the Amending Rule.

120 See clause 6A.7.6(c)(4) of the Amending Rule.

121 See clause 6A.7.6(d) of the Amending Rule.

122 See clause 6A.7.6(e) and the transitional rule of the Amending Rule.

123 See amendments to clauses 6A.4.2, 6A.5.4, 6A.6.6, 6A.6.7, 6A.8.2, 6A.10.1A, 6A.14.1, 6A.17.1 and S6A.1.3 of the Amending Rule.

ABBREVIATIONS

AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
Capex	Capital expenditure
CESS	Capital efficiency sharing scheme
COAG	Council of Australian Governments
Commission	See AEMC
DMIA	Demand management innovation allowance mechanism
DMIS	Demand management incentive scheme
EBSS	Efficiency benefit sharing scheme
ECA	Energy Consumers Australia
EEC	Energy Efficiency Council
ENA	Energy Networks Australia
MCE	Ministerial Council on Energy
NEL	National Electricity Law
NEO	National electricity objective
NER	National electricity rules
NPV	Net present value
Opex	Operating expenditure
PIAC	Public Interest Advocacy Group
R&D	Research and development
RIT-T	Regulatory investment test for transmission
STPIS	Service target performance incentive scheme
TNSP	Transmission network service provider
Totex	Total expenditure

A LEGAL REQUIREMENTS UNDER THE NEL

This appendix sets out the relevant legal requirements under the NEL for the AEMC to make this draft rule determination.

A.1 Draft rule determination

In accordance with section 99 of the NEL the Commission has made this draft rule determination in relation to the rule change request proposed by the ENA.

The Commission's reasons for making this draft rule determination are set out in section 2.4 and in more detail in chapter 3 of this draft rule determination.

A copy of the draft rule is, which is a more preferable rule, is published with this draft rule determination. Its key features are described in section 2.1 of this draft rule determination.

A.2 Power to make the rule

The Commission is satisfied that the more preferable draft rule falls within the subject matter about which the Commission may make rules. The more preferable draft rule falls within s. 34 of the NEL as it relates to regulating the operation of the national electricity market and regulating the activities of persons (including registered participants) participating in the national electricity market.¹²⁴

In addition, the subject matter of the rule change request falls within section 34(2) of the NEL as it relates to matters specified in Schedule 1 to the NEL, being:

- 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.¹²⁵
- 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.¹²⁶

A.3 Additional rule making test – Northern Territory

The National Electricity (Northern Territory) (National Uniform Legislation) Act 2015 provides the Commission with the ability to make a differential rule that varies in its terms between the national electricity system and the Northern Territory's local electricity system. The Commission may make a differential rule if, having regard to any relevant MCE statement of policy principles, it determines that a differential rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule.

The Commission has considered whether a differential rule is required for the Northern Territory electricity service providers and concluded that it is not required in this instance.

¹²⁴ Sections 34(1)(a)(i) and (iii) of the NEL.

¹²⁵ Item 15 of Schedule 1 to the NEL.

¹²⁶ Item 17 of Schedule 1 to the NEL.

This is because the Commission considers that the draft rule will be able to operate in the Northern Territory without special arrangements. Therefore, the Commission has determined to make a uniform rule as it does not consider that a differential rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule.

A.4 Revenue and pricing principles

In addition to having regard to the NEO, the Commission must take into account the revenue and pricing principles in making a rule with respect to (among other things) the regulation of revenue earned, or that may be earned, by transmission network service providers from provision of services that are the subject of a transmission determination.¹²⁷ The application of the revenue and pricing principles is discussed in section 2.2.3 of this determination.

A.5 More preferable rule

Under section 91A of the NEL, the Commission may make a rule that is different (including materially different) to a proposed rule if the Commission is satisfied that, having regard to the issue or issues that were raised by the proposed rule (to which the more preferable rule relates), the more preferable rule will, or is likely to better contribute to the achievement of the NEO. As discussed in Chapter 2 of this determination, the Commission has determined to make a more preferable rule. The reasons for the Commission's decision are set out in section 2.4 of this determination.

A.6 Commission's considerations

In assessing the rule change requests the Commission considered:

- its powers under the NEL to make the rule
- the rule change request
- submissions received during first round consultation
- the ways in which the proposed rule will or is likely to contribute to the NEO.

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles for this rule change request.¹²⁸

The Commission may only make a rule that has effect with respect to an adoptive jurisdiction if satisfied that the proposed rule is compatible with the proper performance of Australian Energy Market Operator (AEMO)'s declared network and system functions.¹²⁹ The final rule is compatible with AEMO's declared network and system functions because it is unrelated to them and therefore does not affect the performance of those functions.

¹²⁷ Refer to section 88B and Items 15 to 24 of Schedule 1 to the NEL. The revenue and pricing principles are set out in section 7A of the NEL.

¹²⁸ Under s. 33 of the NEL, the Commission must have regard to any relevant MCE statement of policy principles in making a rule. The MCE is referenced in the Commission's governing legislation and is a legally enduring body comprising the Federal, State and Territory Ministers responsible for Energy. On 1 July 2011 the MCE was amalgamated with the Ministerial Council on Mineral and Petroleum Resources. The amalgamated council is now called the COAG Energy Council.

¹²⁹ Section 91(8) of the NEL.

A.7 Civil penalties

The Commission cannot create new civil penalty provisions. However, it may, jointly with the AER, recommend to the COAG Energy Council that new or existing provisions of the NER be classified as civil penalty provisions.

The draft rule does not amend any rules that are currently classified as civil penalty provisions under the NEL or National Electricity (South Australia) Regulations. The Commission does not propose to recommend to the COAG Energy Council that any of the proposed amendments made by the draft rule be classified as civil penalty provisions.

A.8 Conduct provisions

The Commission cannot create new conduct provisions. However, it may recommend to the COAG Energy Council that new or existing provisions of the NER be classified as conduct provisions.

The draft rule does not amend any rules that are currently classified as conduct provisions under the NEL or National Electricity (South Australia) Regulations. The Commission does not propose to recommend to the COAG Energy Council that any of the proposed amendments made by the draft rule be classified as conduct provisions.