AEMC

RULE CHANGE

Australian Energy Market Commission

DRAFT RULE DETERMINATION

National Electricity Amendment (Local Generation Network Credits) Rule 2016

Rule Proponents

City of Sydney
Total Environment Centre
Property Council of Australia

22 September 2016

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Reference: ERC0191

Citation

AEMC 2016, Local Generation Network Credits, Draft Rule Determination, 22 September 2016, Sydney

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.

Summary

The Australian Energy Market Commission (AEMC or Commission) has made a more preferable draft rule requiring distribution network service providers (DNSPs) to publish information about expected system limitations. This will offer consistent and accessible information that will enable embedded generators and other providers of non-network solutions to better use existing mechanisms in the National Electricity Rules (NER) in order to defer or reduce the need to invest in the network. In turn, this will maintain a safe, secure and reliable network at the lowest cost to consumers.

The draft rule is made in response to a rule change request by the City of Sydney, the Total Environment Centre and the Property Council of Australia (the proponents). The Commission's draft decision is to not introduce 'local generation network credits' (LGNC) – a new payment mechanism from DNSPs to embedded generators – as proposed in the rule change request. The Commission does not agree that the existing mechanisms are insufficient to incentivise efficient investment in embedded generation and other non-network solutions. It also considers that the proposal is likely to result in higher prices for electricity consumers as payments would be made to an embedded generator whether it is located where a system limitation exists or not.

This draft determination follows extensive engagement with stakeholders in order to thoroughly assess the proposal and alternative solutions. It is also informed by extensive analysis of the likely costs and benefits of different LGNC arrangements. Submissions on this draft determination and draft rule are due by **3 November 2016**.

The energy sector is evolving and moving towards greater diversity in how, where and when electricity is produced and consumed, and how it is delivered. This includes greater use of distributed energy resources (such as embedded generation), batteries, innovative new technologies and business models. The Commission considers that consumer choice should continue to shape the future of the energy sector. This draft rule will supplement the existing technology-neutral mechanisms in the NER that enable consumer choice to decide which technologies and business models prosper.

Summary of the draft rule

In considering the rule change request, the AEMC assessed and consulted on the effectiveness of the existing mechanisms in the NER, including the recent reforms of cost-reflective distribution tariffs that are in the process of being implemented. These mechanisms provide incentives or impose obligations on DNSPs to consider non-network solutions, and create opportunities for providers of non-network solutions to address system limitations.

These mechanisms are generally effective in incentivising efficient investment in embedded generation. They are targeted at the circumstances where embedded generation (and other non-network solutions) can reduce network costs. This occurs where an embedded generator locates in an area with a network system limitation: if it reliably reduces peak demand on the network, the embedded generator can reduce or defer costs of upgrading the network to address the system limitation. If embedded generators locate in areas with spare network capacity and no system limitations, they will not reduce network costs and may increase them.

However, stakeholders highlighted that these existing mechanisms would be more effective if providers of embedded generation and other non-network solution had better and easier access to information about system limitations.

In light of this, the draft rule requires DNSPs to publish a 'system limitations report' in accordance with a template prepared by the Australian Energy Regulator. This report would include information on:

- the name or identifier and location of network assets where a system limitation or projected system limitation has been identified;
- the estimated timing of the system limitation or projected system limitation;
- the proposed solution to remedy the system limitation;
- the estimated capital or operating costs of the proposed solution; and
- the amount by which peak demand at the location of the system limitation or projected system limitation would need to be reduced in order to defer the proposed solution, and the dollar value to the DNSP of each year of deferral.

The requirement to publish a 'system limitation report' supplements current requirements on each DNSP to publish a distribution annual planning report (DAPR). It does so by requiring DNSPs to publish in a consistent and usable format information that is either in the DAPR or that they should readily have access to as a result of preparing the DAPR. In fact, a few DNSPs already include the information required under the draft rule in their DAPRs.

The report would be published annually in conjunction with each DNSP's DAPR. By providing key information about system limitations in a consistent and accessible manner, the report will allow providers of non-network solutions to focus on locations where their solutions could be used to defer or reduce the need to invest in the network. This should allow for more constructive engagement between providers of non-network solutions and DNSPs. Ultimately, this can reduce the costs of delivering electricity to consumers.

The draft rule is specific and proportionate to the issue raised in the rule change request. It is neutral to the technologies used, and carries minimal costs to implement. As such, the Commission considers that the draft rule would, or is likely to, contribute to the achievement of the National Electricity Objective.

Context for the rule change request

An embedded generator is a generator that owns, operates or controls any generating unit that connects directly to a distribution network. Embedded generators vary by type (some use renewable sources such as solar or wind, while others are powered by fossil fuels such as gas or diesel), size (from small rooftop solar panels to commercial plants), and their usage and availability to export electricity when demand on the network is at its highest. Embedded generators may defer or reduce the need to invest in the distribution or transmission network if they can reliably meet local demand at peak times, mitigating the need to transport electricity from other parts of the network. Therefore geographic location of the embedded generator in relation to a system limitation is of crucial importance.

Following rule changes made in recent years, the NER now contain a number of mechanisms to incentivise efficient investment in and use of distributed energy resources (including embedded generation). These include:

- cost-reflective distribution consumption network tariffs;
- network support payments and avoided transmission use of system charges;
- the regulatory investment tests for distribution and transmission (RIT-D/T);
- the capital expenditure sharing scheme (CESS) and the efficiency benefit sharing scheme (EBSS); and
- the demand management incentive scheme (DMIS) and demand management incentive allowance (DMIA).[1]

These mechanisms recognise that the value of investment in non-network solutions, including embedded generation, is dependent on where in the network the non-network solution is implemented.

Data collected by the AEMC indicates that a significant number of network support and avoided TUoS payments are currently being made to embedded generators and other providers of non-network solutions by DNSPs in the NEM. For example, from 2011 to 2015, the Victorian DNSPs CitiPower and Powercor made avoided TUoS payments to 18 different embedded generators totalling over $10 million. Payments to some individual generators during this period exceeded $1 million per year.[2]

The Commission has also made rules that facilitate a more transparent process by which embedded generators connect to the grid. In addition, the small generation aggregator framework rule change made it easier for small-scale generators to participate in the market as an aggregated portfolio. The aggregator may be better placed to negotiate with DNSPs and other market participants. This, in turn, would allow small-scale generators to access different value streams, including network support payments.

1 Note: the NER clauses related to the DMIS and DMIA commences operation on 1 December 2016

2 See: Citipower and Powercor submission to the Essential Services Commission Distributed Generation Inquiry Discussion Paper - Network Value, http://www.esc.vic.gov.au/document/energy/35432-distributed-generation-inquiry-discussion-paper-network-value/

The rule change request

The proponents state that existing network support payment and avoided TUoS mechanisms may be effective in incentivising efficient investment in and use of use of larger-scale embedded generators, but are less accessible for small-scale embedded generators, because:

- the transaction costs to DNSPs and embedded generators of negotiating these arrangements will almost always outweigh the potential benefits offered by a single small-scale embedded generator; and

- DNSPs generally require a guarantee of availability to generate electricity when needed, which is difficult for an individual small-scale embedded generator to offer.

This inability to access the network support payment and avoided TUoS mechanisms is said to risk insufficient investment in small-scale embedded generation and inefficient use of its capacity to export electricity. Ultimately, this could lead to higher prices for consumers. The rule change request seeks to address this issue by introducing a new mechanism that would allow small-scale embedded generators to earn revenue commensurate with their potential to reduce network costs. It does so by proposing that DNSPs would be required to:

- calculate the long-term economic benefits (cost savings) that embedded generators provide to distribution and transmission networks; and

- pay embedded generators LGNCs that reflect those estimated benefits.

LGNCs would be a new negative network tariff, and would create a new payment relationship between DNSPs and embedded generators. Under the proposed rule, any embedded generator would be eligible to receive LGNCs, irrespective of size, availability, and whether or not it was already in place prior to the rule change. However, the payment under these LGNCs could vary depending on the voltage level and location at which each generator connects to the network, and when the embedded generator exports electricity.

Several stakeholders appear to have misunderstood the rule change request and the issue that it seeks to address:

- The proposal is not about "only paying for the part of the network that you use". Generators pay to connect, but do not pay to use the network.

  — How existing network costs are recovered from consumers is addressed by the current rules on network pricing, and the AEMC’s recent rule change on cost-reflective network pricing. Under cost-reflective network prices, a consumer who installs embedded generation and, as a result, reduces their consumption from the network at peak times should pay lower network charges.

- LGNCs would be payable to all embedded generators, and would not reflect the proximity of the embedded generator to consumers. For example, modelling by Marsden Jacob Associates for the AEMC published with this draft determination estimates that a distribution-connected 1MW wind farm in rural New South Wales would receive an annual LGNC payment of $28,000 ($28.34 per kW), while a typical 20 kW commercial-scale solar PV system in central Melbourne would receive about $45 per year ($2.22 per kW).

- The proposal is not about enabling peer-to-peer electricity trading. Efficient allocation of network costs is a prerequisite for peer-to-peer trading; but this can be achieved without LGNCs. LGNCs would simply mean that customers without embedded generators would pay higher network charges to fund payments to customers with embedded generation.

- The proposal is also not about encouraging a move towards more renewable generation. LGNCs would be available to all types of embedded generators. Controllable diesel and gas-fired generators would be likely to receive larger payments than distribution-connected solar PV or wind generators of a similar size under the proposed mechanism. This is because controllable generators are more likely to be generating electricity at times of network peak demand.

The rule change request states that its objective is to reduce the overall costs of the electricity networks by incentivising efficient investment in and use of embedded generation. That is the basis on which the Commission assessed the rule change request.

Reasons for not making the proposed rule

The impact of embedded generation (or any other distributed energy resource) on network costs depends on where the generator connects to the network. It also depends on the time of generation. That is, whether the generator can meet any on-site demand or export electricity when the network is constrained.

LGNCs would be a broad mechanism and would not reflect the highly specific impact of embedded generation on network costs. That means LGNCs would incentivise embedded generation in areas where there is spare capacity and network costs cannot be reduced, and provide insufficient incentives to embedded generation in constrained areas where there is potential to defer or avoid investment in the network. The LGNC proposal fails to account for the importance of location in determining the value that may be provided by embedded generation.

The Commission considered whether the proposed LGNC mechanism could be amended to be made more specific. However, LGNCs would then resemble existing mechanisms such as network support payments. That, in turn, would weaken any justification for introducing LGNCs as an additional mechanism.

The rule change request has been made at a time when mechanisms such as cost-reflective distribution pricing and the DMIS are being implemented. These mechanisms, together with other existing mechanisms, can meet the majority of the proposal's objectives. As such, any additional changes must be proportionate to the remaining issue. Given that the identified issue only applies to small-scale embedded generators, the proposed LGNCs cannot be said to be a proportionate response.

By design, LGNCs also favour embedded generation over other distributed energy resources (such as demand response), and other emerging technologies. That is likely to lead to over-investment in embedded generation at the expense of other, potentially more efficient, non-network solutions.

The design of LGNCs is also likely to result in certain types of embedded generators receiving significantly larger payments than other generators. In particular, controllable diesel and gas-fired generators would be likely to receive much larger payments than solar PV or wind generators of a similar size. Oakley Greenwood, in a report submitted by one of the proponents, notes that export credits in New Zealand mainly encouraged large customers with diesel generators to use them more or install larger generators than they would have otherwise.

The rule change request states that LGNCs should be set such that embedded generators are paid in full for the benefit they may provide, but are not charged for any net costs they impose on DNSPs. It proposes that those costs should be recovered from all other customers. This kind of asymmetric arrangement is likely to incentivise over-investment in embedded generation at a cost to other customers. Further, even in locations where embedded generation may result in the deferral or avoidance of network investment, under the proposal, there would be no cost savings for consumers as the benefit would be paid as an LGNC.

The form of LGNC proposed in the rule change request would establish a new payment relationship between DNSPs and embedded generators. Even if LGNCs were to be processed by retailers, rather than by DNSPs, there will be material costs in arranging payments to embedded generators that are not also retail customers. It is clear that, no matter the design, LGNCs are likely to be a costly mechanism to implement and administer. These costs would be passed on to consumers and would likely result in higher electricity charges for all consumer

Analysis by the Institute for Sustainable Futures (ISF) in support of the rule change request estimates that LGNCs can result in material cost savings, but only by excluding small-scale embedded generators – the opposite of what is proposed in the rule change request. The ISF's results also rely on projections that peak demand for electricity will increase significantly more than forecast by the Australian Energy Market Operator (AEMO). Based on AEMO's latest demand forecasts, the ISF's analysis shows that even a modified LGNC scheme that excludes all existing embedded generators and all small solar PV generators would increase electricity prices for consumers.

Analysis by AECOM for the AEMC that is published with this draft determination shows that, even where there is a projected system limitation, LGNCs can significantly increase costs to consumers while offering little or no deferral of network investment. AECOM specifically assessed three case studies where an investment need is expected, as these represent the most likely opportunities for embedded generation to reduce network costs.

This analysis found that, for all three case studies, the level of peak demand reduction with LGNCs was small and was insufficient to defer investment in the network. As such, there was no reduction in network costs. The cost of paying the LGNCs ranged from $1 million to $18 million in the three case studies. This net cost would need to be recovered through an increase to network charges paid by all consumers. AECOM's analysis does not suggest that embedded generation cannot reduce network costs. Rather, it shows that any benefit from additional embedded generation as a result of introducing LGNCs would be far outweighed by the cost of the LGNCs.

Overall, the Commission considers that the proposed rule change would not, or is not likely to, contribute to the achievement of the National Electricity Objective. This is based on both a principled assessment of the proposed LGNCs (and its different variations) and on an empirical assessment of the relative costs and benefits. The draft rule is a more proportionate response to the issues raised in the rule change request.

Contents

1 Introduction

On 14 July 2015, the City of Sydney, the Total Environment Centre and the Property Council of Australia (the proponents) submitted a rule change request to the Australian Energy Market Commission (the AEMC or Commission). The proposed rule would, if implemented, require distribution network service providers (DNSPs) to pay a 'local generation network credit' (LGNC) to all eligible embedded generators in their network areas.[3]

The rule change request uses the term 'local generation' as shorthand for small-scale embedded generation. Embedded generation is also commonly known as distributed generation. For consistency, this draft determination uses the term 'embedded generation' throughout, since it is the term used in the NER.[4]

The underlying issue raised in the rule change request is whether the National Electricity Rules (NER) provides sufficient incentives for efficient investment in both embedded generation and in the transmission and distribution networks. To determine if an issue exists and what, if any, changes to the NER may be required, it is imperative to first examine the NER mechanisms that provide these incentives.

1.1 Embedded generation

Historically, the vast majority of electricity delivered to Australian consumers has been through a centralised system. That is:

- electricity was produced by generators connected to the high-voltage transmission network, and typically located some distance from consumers;
- the electricity produced was then transported over the high-voltage transmission network and the lower voltage distribution network;
- the distribution network delivered the electricity to the consumer.

However, an increasing share of electricity is being produced by generators that are located nearer to consumers, and sometimes in the same physical location (for example, rooftop solar panels supplying the house on which they are installed).

The NER defines embedded generators as generators that are connected directly to the distribution network. They may be connected at the sub-transmission, low-voltage or

3 Oakley Greenwood, 'Local Generation Network Credit Rule Change Proposal', Submission to: Australian Energy Market Commission, Proposed by: City of Sydney, Total Environment Centre, Property Council of Australia, 14 July 2015 ('rule change request'). The rule change request is available on the AEMC's website at: www.aemc.gov.au

4 Chapter 10 of the NER defines an embedded generator as a registered generator who owns, operates or controls an embedded generating unit. An embedded generating unit is, in turn, defined as a generating unit connected within a distribution network and not having direct access to the transmission network. Chapter 5A of the NER defines embedded generator as a person that owns, controls or operates an embedded generating unit.

feeder level of the distribution network. As a result of being connected directly to the distribution network, embedded generators tend to be closer to consumers than traditional large-scale transmission-connected generators.

The electricity produced by embedded generators can be:

- used by the embedded generator's owner to offset its own on-site consumption; or
- sold either through the National Electricity Market (NEM) or to a local retailer.

Where electricity produced by an embedded generator helps address a network system limitation, it can also earn payments from a DNSP or transmission network service provider (TNSP) for any such network support that it provides.

The electricity sector is evolving. This evolution includes:

- a greater role for DNSPs in integrating distributed energy into the distribution network;
- two-way flows of energy over the distribution network as a result of more embedded generation;
- increased adoption of non-network alternatives of all types, including demand management, embedded generation and batteries; and
- improved information for consumers allowing them to make informed decisions about investment in distributed energy resources and their use of energy.[5]

As a result of this evolution, the role of embedded generators is likely to change over time.

1.1.1 Types of embedded generation

Embedded generators vary in terms of:

- **Fuel source:** embedded generators may use renewable fuel sources such as wind, water or sunlight, or be powered by fossil fuels such as natural gas or diesel fuel.
- **Installed capacity:** embedded generators range in size from small rooftop solar photovoltaic (PV) systems with a capacity of around 1 KW to facilities that are significantly larger, such as:
  - wind farms and commercial solar farms; and
  - gas-fired co-and tri-generation plants located in commercial buildings.

5 Distributed energy resources is a catch-all term that covered embedded generation, demand response and energy efficiency improvements.

- **On-site usage:** different types of embedded generators will inject a different proportion of the electricity they generate into the grid:
  - some embedded generators will have some or all of the electricity they generate consumed on-site and only export the balance - for example, household solar PV systems;
  - other embedded generators, such as large scale wind farms, will export nearly all the electricity they generate.[6]
- **Availability:** some forms of embedded generation can be reliably called upon to supply a fixed amount of electricity for a set period (diesel or gas-fired generators can usually be switched on at any time), whereas other sources are intermittent (such as wind or solar).[7] There are three elements of an intermittent generator's output that are relevant to the rule change request:
  - their output can be variable - for example, the production of solar generation depends on cloud cover;
  - their output can be difficult to predict - it is influenced by the elements, so there is no guarantee that a particular solar or wind generator will be available at a particular time; and
  - their output may be difficult to control - as output in influenced by the elements, the embedded generator is not able to typically turn on or off as needed.

The benefits provided by different types of embedded generators to DNSPs (and potentially TNSPs) at a particular time and place will vary considerably.[8] In some cases, embedded generators will provide a clear benefit and in other circumstances embedded generation may increase network costs.

1.1.2 Embedded generation and the network

Embedded generation may have two distinct impacts on electricity networks. On the one hand, embedded generation may reduce demand on distribution and transmission infrastructure during the network peak. In the long term this may mitigate the need to invest in maintaining, upgrading or replacing the networks.

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6 There is often little difference between these types of generators and equivalent transmission-connected generators, aside from the fact that they are connected to the distribution network.

7 Electricity storage (such as batteries) may be used to mitigate the intermittency of renewable energy.

8 In the same way that embedded generators may reduce the need to invest in the distribution network, they may reduce the need to invest in the transmission network. This is due to a greater proportion of local electricity requirements being met by embedded generation.

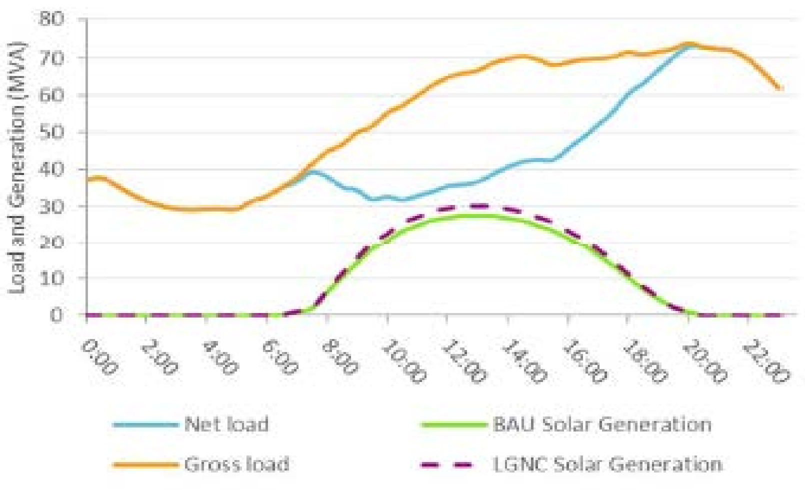
Specifically, consumers with embedded generation may be able to:

- reduce their reliance on the grid during peak periods by meeting a greater proportion of their requirements from the electricity generated by an on-site embedded generator; and
- export surplus energy into the distribution network at peak times, reducing the need to transport electricity from generators connected to the transmission network and potentially reducing the need to invest in expanding, maintaining or replacing the network.

In practice, the extent to which embedded generation will give rise to these benefits depends on the specific circumstances. If there is an imminent need to invest to address a system limitation, embedded generation of sufficient capacity, reliability and controllability may be able to defer or down-size that investment. Where this is not the case, the benefits to the network business and its customers diminish considerably and, in fact, embedded generation may lead to additional costs.

For example, household solar PV has started to shift the peak period on some parts of the distribution network. This results in a peak period that occurs later in the day than previously, and outside the time in which solar PV is generating electricity. The result is that solar PV is less capable of meeting on-site consumption or exporting energy during the network's peak period. As a result, it is less capable of reducing the network costs of meeting peak demand. This effect is illustrated in Figure 1.1 below.

Figure 1.1: Time shift of network peak demand



Source: AECOM, Modelling the impact of Embedded Generation on Network Planning, 29 August 2016, p.37; Figure 30, Flemington Data Set 2, 10% solar PV on Baseline, 14 January 2047

Network businesses may also face additional costs associated with integrating embedded generators. Currently, an embedded generator must pay a charge to connect to the distribution network. This charge varies with the type of connection - standard control service, alternative control service or a negotiated service. This classification depends on the size of the embedded generator, whether it is co-located with a consumer and by network area. Once connected, embedded generators do not pay to use the network in order to export the electricity that they produce.

Embedded generation may also result in other costs being incurred by DNSPs (and potentially TNSPs), such as:

- any additional spending on the networks to maintain the reliability of the distribution and transmission networks (for example, upgrading transformers or switchgear in order to prevent the risk of higher fault levels); and
- an increase in intermittent sources of embedded generators may cause existing generation assets to be ramped up or ramped down more often (potentially at significant cost), or require the Australian Energy Market Operator (AEMO) to procure and dispatch more ancillary services to manage frequency variations.[9]

Given the potential benefits and costs of embedded generation, the NER should not presume that any one solution to address a system limitation benefits consumers more than others. The appropriate solution will vary from case to case. Consequently, the NER should enable an efficient balance of network solutions (ie poles and wires) and non-network solutions (such as embedded generation or demand response).

1.2 Existing mechanisms in the National Electricity Rules

The Commission has given a great deal of consideration to promoting an efficient balance of network and non-network solutions in recent times and continues to do so. For example, the role of non-network solutions formed a key aspect of several recommendations in the AEMC's Power of Choice review.[10] The NER now contain several mechanisms and schemes to incentivise the efficient balance of network and non-network solutions. These include:

- **Cost-reflective distribution network tariffs:**[11] the rule change requires DNSPs to develop prices that better reflect the costs of providing services to individual consumers so that they can make more informed decisions about their electricity use. Cost-reflective network tariffs incentivise investment in non-network solutions, including embedded generation co-located with load, that result in reduced use of the network during peak times.
- **Network support payments:**[12] embedded generators with capacity greater than 5MW can negotiate with a TNSP to receive network support payments. These payments must reflect the economic benefits the embedded generator is

9 Frequency control ancillary services are used by AEMO to balance, over short intervals, variations in supply and demand .

10 AEMC 2012, Power of Choice review - giving consumers options in the way they use electricity, Final Report, 30 November 2012, Sydney

11 AEMC 2014, Distribution Network Pricing Arrangements, Rule Determination, 27 November 2014, Sydney

12 See: NER clause 5.4AA

providing to the TNSP by delaying or avoiding investment in the transmission network. Network support payments may also be negotiated between DNSPs and embedded generators. However, unlike with TNSPs, the principles for the negotiation of network support payments with DNSPs are not specified in the NER.

- **Avoided Transmission Use of System (TUoS) charges:**[13] DNSPs are required to make payments to embedded generators with a capacity of more than 5MW if the presence of those generators reduces the electricity supplied to the distribution network from the transmission network.[14] The avoided TUoS payment reflects transmission charges the DNSP saves, ie the locational TUoS charge.

- **Regulatory Investment Test for Distribution (RIT-D) and Transmission (RIT-T):**[15] require DNSPs and TNSPs, respectively, to consider the costs and benefits of all credible network and non-network solutions where an investment need is projected to cost at least $5 million for distribution or $6 million for transmission.[16]. In some circumstances, the benefits will be maximised or the costs minimised, by providing embedded generation capacity rather than a network solution.

- **Distribution network planning and expansion framework:**[17] this rule change introduced obligations on DNSPs to annually plan and report on assets and activities that are expected to have a material impact on the network in a distribution annual planning report (DAPR). The rule also includes a number of demand-side engagement obligations on DNSPs. This provides transparency on DNSPs' planning activities and decision making, and better enables non-network solution providers to put forward options - including embedded generation - as credible alternatives to network investment.

- **Capital Expenditure Sharing Scheme (CESS) and Efficiency Benefit Sharing Scheme (EBSS):**[18] these schemes provide DNSPs and TNSPs with incentives to invest in and operate their networks efficiently by allowing them to retain a portion of any cost savings relative to allowances set by the Australian Energy Regulator (AER). The rest of the savings are passed on to consumers through lower network charges. These schemes incentivise a DNSP or TNSP to substitute

13 See: NER clause 5.5(h)

14 Some DNSPs have been offering avoided TUoS payments to embedded generators of all sizes. See, for example, ActewAGL's renewable generation tariff for 2015/16.

15 See: NER clauses 5.16 and 5.17, respectively

16 Pursuant to NER clauses 5.16.3 and 5.17.3, there are exceptions to when a DNSP is required to complete a RIT-T or RIT-D including when the project is to address an urgent and unforeseen network issue, is related to the refurbishment or replacement of existing assets.

17 AEMC 2012, Distribution Network Planning and Expansion Framework, Rule Determination, 11 October 2012, Sydney, Part B of Chapter 5

18 See: NER clause 6.5.8A and 6.5.8, respectively

a non-network solution for a previously anticipated investment in the network, if the former is more efficient.

- **Demand Management Incentive Scheme (DMIS):**[19] the AER is required to publish an incentive scheme for network businesses to implement non-network investments, where it is efficient to do so.

- **Demand Management Innovation Allowance (DMIA):**[20] the DMIA will provide DNSPs with funding to undertake research and development in demand management projects. The allowance is used to fund innovative projects that have the potential to deliver ongoing reductions in total demand or peak demand, which may include embedded generation initiatives.

- **Small generation aggregator framework:**[21] this rule change seeks to reduce barriers to small generators participating in the market by enabling them to aggregate and sell their output through a third-party (a Market Small Generator Aggregator). This makes it easier for those parties to offer non-network solutions, and for DNSPs to procure those options when it is efficient to do so.

The Commission has also made rules to improve the process by which embedded generators - both large and small (less than 5 MW) - connect to the grid. The 'Connecting Embedded Generators' rule seeks to achieve this through a more transparent connection process, with defined timeframes and requirements on the DNSP to disclose relevant information.[22] In addition, the 'Connecting Embedded Generators under Chapter 5A' rule offers small-scale embedded generators a choice of two frameworks (the embedded generation connection process in Chapter 5 of the NER or the connection process in Chapter 5A of the NER) when negotiating a connection to a distribution network.[23]

A number of the mechanisms listed above have already been implemented, while others are in the process of being implemented. As such, the full potential of these mechanisms is yet to be realised. Box 1.1 summarises initiatives by one of the DNSPs - Ergon Energy - that use the above mechanisms.

19 See: NER clause 6.6.3; note this new rule commences operation on 1 December 2016

20 See: NER clause 6.6.3A; note this rule commences operation on 1 December 2016

21 AEMC 2012, National Electricity Amendment (Small Generator Aggregator Framework) Rule 2012, Rule Determination, 29 November 2012, Sydney

22 AEMC 2014, Connecting Embedded Generation, Rule Determination, 17 April 2014, Sydney

23 AEMC 2014, Connecting Embedded Generators under Chapter 5A, Rule Determination, 13 November 2014, Sydney

Box 1.1 Ergon Energy case study

Ergon Energy has implemented several targeted demand management initiatives in its network area. These aim to incentivise customers to reduce demand at specific locations and specific times. This, in turn, allows Ergon to manage peak demand on its network without additional investment. These demand management initiatives include:

1. **Demand Management Incentive Map:**[24]The map is a communication tool to allow consumers and market participants to identify the value and location where customers may be able to earn payment in return for reducing their usage at peak times. The map is interactive and provides information down to the street or property level. The map identifies, through colour coding, whether a cash-back incentive is available currently or projected to be available in the next two years (based on projected demand growth);

2. **MacKay Northern Beaches and Townsville North West Incentive Program:**[25]A cash-back program is currently available for business customers in the MacKay Northern Beaches and Townsville North West area to incentivise them to reduce peak demand on the network. Customers can earn $200 per KVA of demand reduction in the Mackay Northern Beaches area and $350 per KVA of demand reduction in the Townsville North West area. Examples of activities that may qualify a business consumer for the cash-back program include:

   - upgrading appliances and lighting to more energy-efficient models;
   - permanently removing or shifting electricity usage from the time of the network peak to off-peak periods; or
   - activity that results in an improvement to the power factor on the network.[26]

3. **Network support payments**: Ergon has several network support agreements in place where demand management initiatives address an identified issue on the network. In the year 2014/2015, Ergon paid $2.58 million for a total of 34 MVA of network support.

24 See Ergon Energy's website: https://www.ergon.com.au/network /manage-your-energy/incentives/search-incentives (accessed on 13 September 2016)

25 Further details on these programs can be accessed via Ergon's website at: https://www.ergon.com.au/network/manage-your-energy/incentives/mackay-northern-beaches or https://www.ergon.com.au/network/manage-your-energy/incentives/townsville (both accessed on 13 September 2016

26 Power factors is the ration between the kW and kVA drawn by an electrical load where the kW is the actual load power and the kVA is the apparent lower power

2 The rule change request

This chapter summarises the LGNC rule change request, the issue identified by the proponents and the proposed solution. The chapter also outlines the process the AEMC took to assess the rule change request, and provides detail on how to make a submission on this draft determination.

2.1 Details of the rule change request

On 14 July 2015, the proponents submitted a rule change request to the AEMC that would alter the payment arrangements for embedded generators in the NEM. The rule change request requires DNSPs to:

- calculate the long-term economic benefits (cost savings) that embedded generators provide to distribution and transmission networks; and
- pay embedded generators a negative tariff (the LGNC) that reflects those estimated long-term benefits.

The rule change request focussed on small-scale embedded generation, but the proposed rule would require DNSPs to pay LGNCs to all embedded generators, regardless of their size. The Commission has assessed the proposal on the basis that it would apply to all embedded generators.

2.2 Rationale for the rule change request

The proponents consider that the NER do not allow small-scale embedded generators to earn revenue commensurate with their potential to defer or avoid network costs.[27] The network support payments, avoided TUoS payments and RIT-D arrangements described in chapter 1 of this draft determination are said to be less accessible to small-scale embedded generators because:

- the transaction costs to the network business and embedded generator of negotiating these arrangements will almost always outweigh the potential benefits on offer from a single generator; and
- the networks generally require the provision of firm capacity, which is difficult for an individual small-scale embedded generator to offer.[28]

The proponents acknowledge that the current NER provisions "may facilitate efficient investment in larger-scale embedded generation".[29] They also state that the

27 See: rule change request, p. 2.

28 A generator offers 'firm capacity' when it is able to guarantee that it will inject a certain amount of electricity (eg 5MW) at a particular time (eg between 4pm and 4.30pm if that is when demand tends to be at its highest in that part of the network). Certain types of generator may be unable to provide firm capacity because their ability to generate is dependent on factors that are outside the generator's control, such as whether the sun is shining or the wind is blowing at that time.

introduction of cost-reflective distribution pricing provides signals regarding electricity consumption. However, distribution prices do not explicitly address situations where customers with small-scale embedded generators generate more energy than they consume, and may want to export that additional electricity to the grid.

The proponents take the view that the lack of an export signal to small-scale embedded generators is problematic because:

- the aggregate benefits to the network business offered by a portfolio of small-scale embedded generators may be material; and
- it may be less important for an individual small-scale embedded generator to offer firm capacity if it is part of a broader portfolio of embedded generators. Such a portfolio may include both generators that offer firm capacity (eg diesel and gas-fired generators) and intermittent generators (eg wind and solar).[30]

The proponents contend that the gap they identified in the NER has resulted, or will result, in:

- not enough small-scale embedded generation and too much network investment, including when the former would be less costly than the latter; and
- existing small-scale embedded generation being used inefficiently, with users having an incentive to maximise consumption rather than exporting when it is efficient to do so.

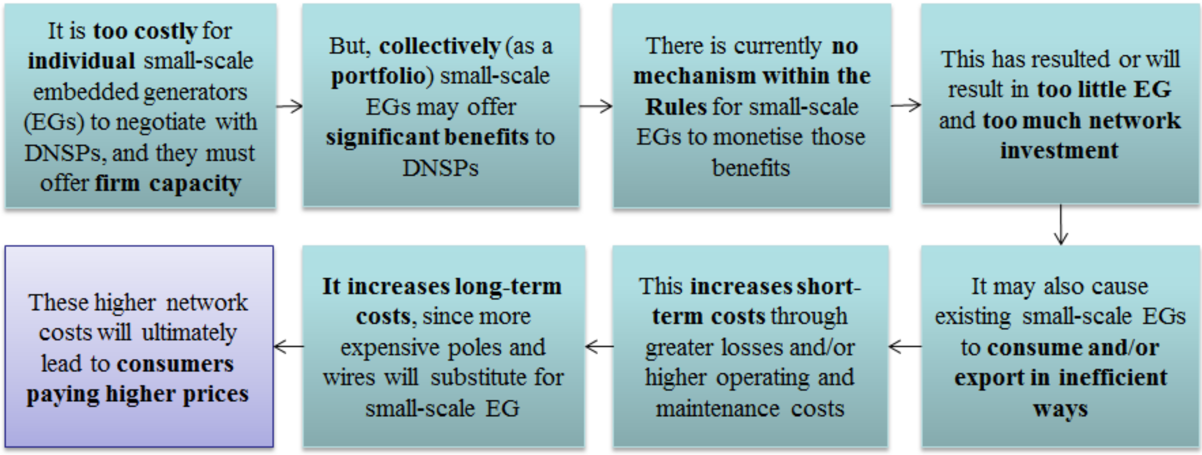
The overall effect is implied to be higher costs in both the short-term (through higher electricity losses due to greater use of the grid) and the long-term (through more expensive network capital investment). These costs are, ultimately, borne by consumers. It is important to note that the impact of embedded generation on the wholesale market through electricity losses is not included in the value of LGNCs, and is outside the scope of the rule change request.

Figure 2.1 summarises the AEMC's understanding of the issue that has motivated the rule change request.

29 See: rule change request, p. 15.

30 See: rule change request, pp. 12 and 15

Figure 2.1 Summary of perceived issue



2.3 Solution proposed in the rule change request

The proposal is to amend the NER to introduce LGNCs, which would be a network price signal for exported energy.[31] Specifically, this would involve:

- For the AER: developing a guideline for LGNCs.
- For DNSPs:
  - developing a negative network tariff that reflects any long-term benefits that embedded generators provide in terms of:
    - (a) deferring or down-sizing network investment ('capacity support'); and
    - (b) reducing operating and maintenance costs ('avoided transportation costs').
  - paying embedded generators LGNCs equal to that difference between the benefits and costs, and based on their net electricity exports.

According to the proposal, the value of the LGNC could be adjusted annually in line with each DNSP's approved pricing proposals.

The rule change request is clear that the value of a LGNC should reflect potential cost savings in both the distribution and transmission networks.[32] For distribution, the

31 The value of the exported energy itself would need to be determined separately. For example, through the price paid if the energy is sold through the NEM as market generation or sold to a local retailer.

32 See: rule change request, p8. The proposed rule does not address transmission cost savings or contain a mechanism to include those savings in LGNC payments. But since the intention of the rule change request is clear, the proposal is assessed on the basis that the intention is to include any such savings.

value of those savings would be based on the long run marginal cost (LRMC) of investment in the distribution network. For transmission, the value of these savings would be based on avoided TUoS charges.

The rule change request is unclear on whether DNSPs would have to forecast LGNC payments as part of their operating expenditure, and be exposed to any deviation from that forecast, or whether the costs of LGNCs would be passed-on to consumers in full.

2.4 The rule making process to date

On 10 December 2015, the AEMC published a notice that it commenced the rule making process, as well as a consultation paper on the issues raised by the rule change request.[33] The Commission received 59 submissions on the rule change request as part of the first round of consultation.[34] Where appropriate, issues raised by stakeholders in their submissions are addressed throughout this draft determination. A summary of issues that have not been explicitly addressed in this draft determination, and the Commission's response to them, is provided in Appendix A.

This draft determination follows extensive engagement with stakeholders in order to thoroughly assess the proposal and alternative solutions. That included:[35]

- an introductory webcast that explained the rule change request and the AEMC's approach to assessing it, with an opportunity for stakeholders to ask questions on these issues;
- two full-day public workshops to discuss the issues raised in the rule change request, the proposed solution and potential alternative solutions;
- a half-day discussion group to discuss the issues raised in the rule change request with local government, consumer and environmental stakeholders who were unable to attend the public workshops; and
- 34 bilateral meetings with the proponents and other stakeholders.

2.5 Consultation on draft rule determination

The Commission invites submissions on this draft rule determination and more preferable draft rule by **3 November 2016**. Following consideration of submissions, the Commission intends to publish its final determination on 8 December 2016.

33 This notice was published under section 95 of the National Electricity Law (NEL).

34 The consultation paper and submissions are available on the AEMC's website at: www.aemc.gov.au/Rule-Changes/Local-Generation-Network-Credits

35 Summaries of the webcast, public workshop and discussion group are available on the AEMC's website at: www.aemc.gov.au/Rule-Changes/Local-Generation-Network-Credits

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 29 September 2016.

Submissions and requests for a hearing should quote the project number "ERC0191". They may be lodged online at www.aemc.gov.au or by mail to:

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

3 Draft rule determination

The Commission's draft rule determination is to make a more preferable draft rule. The draft rule obliges DNSPs to prepare and publish a 'system limitations report' in accordance with a 'system limitation template' that the AER would be required to publish. This report will provide consistent, summarised and useable information on current and expected constraints on each distribution network. This would enable providers of non-network solutions to more easily identify opportunities to defer or avoid network investment, and to propose these to DNSPs.

This chapter outlines the Commission's:

- rule making test for changes to the NER;
- assessment framework for considering the rule change request; and
- consideration of the rule change request and the draft rule against the National Electricity Objective (NEO).

From 1 July 2016, the National Electricity Rules (NER), as amended from time to time, apply in the Northern Territory (NT),[36] subject to derogations set out in Regulations made under the NT legislation adopting the NEL.[37] Under those Regulations, only certain parts of the NER have been adopted in the Northern Territory. As the draft rule relates to parts of the NER that do not apply in the Northern Territory, the Commission has not assessed the draft rule against additional elements required by NT legislation.[38]

Further information on the legal requirements for making this draft rule determination is set out in Appendix B.

3.1 Rule making test

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 NEO.

36 Details on the parts of the NER adopted by the Northern Territory can be found on the AEMC's website at: http://www.aemc.gov.au/Energy-Rules/National-electricity-rules/Rules-(NT)/National-Electricity-Rules-(NT)-Version-1

37 National Electricity (Northern Territory) (National Uniform Legislation) (Modifications) Regulations.

38 *National Electricity (Northern Territory) (National Uniform Legislation) Act 2015*

The NEO is:[39]

> "to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system."

The relevant aspects of the NEO for this rule change request are the promotion of efficient investment in, and operation of, electricity networks and embedded generators for the long-term interests of consumers with respect to:

- **price** – whether the proposal is likely to decrease or increase the prices paid by consumers for electricity; and
- **reliability** and **security** of electricity supply experienced by consumers.

The Commission may make a more preferable rule if it is satisfied that, having regard to the issues raised, it is likely to better contribute to the achievement of the NEO.[40] To determine whether the proposed rule, or a more preferable rule, is likely to contribute to the achievement of the NEO, the Commission applied the assessment framework described in section 3.2. Although the issues identified in the rule change request focus on small-scale embedded generation, the proposal itself would apply to all embedded generators, irrespective of size. As a result, the assessment framework reflects that breadth of application.

3.2 Assessment framework

Promoting the long-term interests of consumers means that network quality, safety, reliability and security of supply requirements are met at efficient long-term cost, taking into account both network and non-network (including embedded generation) options. This will be achieved if:

- Demand is met at the **lowest total system cost** (given reliability standards and other regulatory obligations) – the NER should incentivise DNSPs to provide network services at the lowest total cost by using an efficient combination of network and non-network solutions.
- **Prices reflect those costs** – customers should face tariffs that reflect the underlying costs of supply so that consumption and, subsequently, investment is not inefficiently deterred or encouraged.

39 NEL s.8.

40 NEL s.91A.

- There is **efficient investment in new assets** over time – the NER should incentivise DNSPs to efficiently invest in network solutions and purchase non-network solutions at the right times and in the right places.

The first step in assessing the rule change request was to examine whether the rule change request had in fact identified an issue with the existing NER provisions. The key question here is whether the NER provides sufficient incentives to invest in and operate embedded generation efficiently, and for DNSPs to procure it when it is the least cost solution to a system limitation.

If an issue with the NER is identified, the next step is to establish criteria for assessing whether the rule change request - or any alternative option that can be implemented as a more preferable rule - would promote achievement of the NEO. These criteria are discussed in section 3.2.1.

3.2.1 Criteria for assessing the rule change request and alternative options

The criteria for assessing the rule change request against the NEO were developed with stakeholders at a workshop held on 25 February 2016.[41] The criteria are:

- **Specificity** – the solution to the issue raised in the rule change request should recognise that the impact of embedded generation on the network (positive or negative) would vary considerably based on the location where the generator connects to the network and on the timing of when it exports electricity.[42]

- **Proportionality** – the solution should be consistent with existing provisions in the NER that have similar objectives (ie those provisions described in section 1.2), some of which are still being implemented, and not unnecessarily duplicate existing mechanisms.

- **Technology-neutrality** – the solution should be consistent with the principle that the NER be agnostic to specific technical approaches, and that consumer choice should determine what technology is adopted.

- **Symmetry** – the solution should allocate the net benefits and costs of embedded generation so as to incentivise their efficient investment and use.[43]

- **Cost minimisation** – the solution should address the issue raised in the rule change request at the lowest cost of implementation and administration for all affected parties.

41 A summary of the discussion at the workshop can be found on the AEMC's website at: http://www.aemc.gov.au/Rule-Changes/Local-Generation-Network-Credits

42 A similar consideration applies for non-network solutions other than embedded generation.

43 This also applies to any other non-network solution.

3.3 The draft more preferable rule

The Commission's draft more preferable rule addresses the issue raised in the rule change request - incentivising efficient investment in and use of embedded generation as an alternative to network investment. The rule change request seeks to address this issue by introducing a new payment mechanism (LGNCs) into the NER. In contrast, the draft rule seeks to make it easier for providers of embedded generation and other non-network solutions to utilise the existing mechanisms.

The draft rule promotes an efficient balance of network and non-network solutions by providing interested parties with consistent and usable information. This would make it easier for providers of non-network solutions to propose alternatives that could defer or reduce the need for DNSPs to invest in the network.

The draft rule would require the AER to develop a 'system limitation template', which DNSPs would use to provide information on:

- the name or identifier and location of network assets where a system limitation or a projected system limitation has been identified during the forward planning period;[44]
- the estimated timing of the system limitation or projected system limitation;
- the DNSP's proposed solution to remedy the system limitation;
- the estimated capital and operating costs of the DNSP's proposed solution; and
- the amount by which peak demand at the location of the system limitation or projected system limitation would need to be reduced in order to defer the proposed solution, and the dollar value to the DNSP of each year of deferral.[45]

The draft rule also requires each DNSP to annually complete the template by publishing a 'system limitations report' on its website at the same time as its DAPR.

3.4 Summary of reasons

As outlined in section 1.2, the Commission has made several recent rules to incentivise DNSPs to implement, where efficient, non-network solutions rather than traditional network solutions.

These mechanisms were introduced with the objective that electricity networks be operated in a safe, secure and reliable manner at the lowest cost for consumers. These mechanisms are designed not to provide an advantage to any specific technology or type of non-network solution. Rather, they work together with the economic regulatory

44 For distribution the forward planning period is a minimum of five years, see: NER, 5.13.1

45 The value to the DNSP, in this regard, means the difference between the costs incurred with the non-network solution in place and the costs that would have been incurred without the non-network solution in place.

framework to incentivise efficient investment in and operation of the networks by allowing network businesses to consider any existing, emerging or new technology or process in determining the efficient solution to system limitations.

The NER contain several mechanisms to incentivise network businesses to adopt the most efficient of these options. The AER will only allow network businesses to recover the efficient costs of addressing any system limitations when it sets the allowance for a network business' regulated revenues.

The rule change request claims that the NER do not allow small-scale embedded generators to earn revenue commensurate with their potential to reduce network costs.[46] Even though the issue raised is specific to small-scale embedded generation, the proposed LGNCs would apply to all embedded generators, regardless of size.

The Commission does not agree that the NER do not currently contain sufficient mechanisms to financially reward small-scale embedded generators where they offer an efficient alternative to network investment and reduce network costs. It considers that the NER provide sufficient incentives to ensure an efficient balance of network and non-network solutions. This includes, where appropriate, payments for non-network solutions, such as embedded generation. Many of these mechanisms are relatively new, and some are still being implemented. As a result, it will take some time before these mechanisms fully affect the day-to-day operation of network businesses.

Rather, the Commission understands that some providers of non-network solutions find it difficult to capitalise on the existing mechanisms because the relevant information is often hard to find or make use of. For example, DNSPs take different approaches to the level of detail and structure of their DAPRs. The draft rule is aimed at addressing this underlying cause of the issue raised in the rule change request.

3.4.1 Reasons for not making the proposed rule

The impact of embedded generation on the network depends on numerous factors,[47] including the voltage level and location at which the generator connects to the network, and the ability to control when it exports electricity. As such, embedded generators in specific situations can either reduce or increase network costs. The proposed LGNCs are a broad mechanism that provides a financial benefit to all eligible embedded generators regardless of whether they reduce network costs. Such a broad mechanism will not promote efficient investment in embedded generation, and is likely to increase the costs that consumers pay for electricity.

The Commission considered whether to make a more specific version of LGNCs. However, the more specific LGNCs are made, the more they would resemble existing mechanisms such as network support payments. Network support payments aim to address situations in which non-network solutions can address specific system limitations. A highly-specific LGNC mechanism that only resulted in payments to

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46 See: rule change request, p.2

47 This is also true for other types of distributed energy resources, such as demand response.

embedded generators that addressed network limitations would not better promote the NEO than the existing network support payments mechanism.

The rule change request has been made at a time when mechanisms such as cost-reflective distribution pricing and the DMIS are still being implemented. The majority of the proposal’s objectives can be met can be met through these and existing mechanisms such as network planning obligations, network support payments, avoided TUoS payments, the RIT-D and RIT-T and the CESS and EBSS. As such, any additional changes must be proportionate to the remaining issue. Given that the identified issue only applies to small-scale embedded generators, the proposed LGNCs cannot be said to be a proportionate response.

The proposed LGNCs would be an additional mechanism in the NER. Unlike the mechanisms described in section 1.2, LGNCs are specifically targeted at embedded generation, rather than the broader class of non-network solutions. This runs contrary to the Commission's objective that, as much as practical, the NER should be neutral to the technologies used. Technology-neutrality allows the market to develop and innovate without one type of technology being given an advantage over others. When the market is allowed to innovate without interference, the choices that consumers make determine which technologies prevail. The LGNC proposal would distort consumer choice by favouring embedded generation over other non-network solutions (such as demand response).

The rule change request states that LGNCs should be set such that embedded generators would be paid in full for the benefit they may provide, but would not be charged for any net costs they impose on DNSPs. It proposes that those costs should be recovered from all other customers. This kind of asymmetric arrangement is likely to incentivise over-investment in embedded generation at a cost to other customers.

The form of LGNCs in the rule change request would also establish a complex new payment relationship between DNSPs and embedded generators. Even if payments were to be processed by retailers, rather than by DNSPs, there will be material costs in arranging payments to embedded generators that are not also retail customers. It is clear that, no matter the design, LGNCs are likely to be a costly mechanism to implement and administer. These costs would likely result in higher electricity charges for all consumers.

Analysis by AECOM for the AEMC shows that, even where there is a projected system limitation, LGNCs are likely to significantly increase costs to consumers while offering little or no deferral of network investment.[48] This analysis is discussed in chapter 4, and the AECOM report is published alongside this draft determination.

Analysis by the Institute for Sustainable Futures (ISF) in support of the rule change request estimates that LGNCs can materially reduce network costs, but only by excluding small-scale embedded generators – the opposite intent to the rule change

48 AECOM, Modelling the impact of embedded generation on network planning, report to the Australian Energy Market Commission, 29 August 2016.

request.[49] The ISF's results also rely on projections that peak demand for electricity will increase significantly more than currently forecast by the AEMO.[50] Based on AEMO's latest demand forecasts, the ISF's analysis shows that even a modified LGNC scheme that excludes all existing embedded generators and all small solar PV generators would increase electricity prices for consumers.

Overall, the Commission considers that the proposed rule change would not, or is unlikely to, contribute to the achievement of the NEO. Further details of the Commission's reasons for not making the proposed rule are set out in chapter 4.

3.4.2 Reasons for making the draft rule

The Commission considers that an issue does exist regarding the ability of providers of non-network solutions (including embedded generators) to take advantage of the mechanisms that exist in the NER. The draft rule will provide relevant information in a consistent and usable format to allow providers of non-network solutions to more easily leverage these mechanisms. As such, the draft rule is specific and proportionate to the issue raised in the rule change request. The draft rule is neutral to the technologies used, allowing consumer choice to determine the future of the energy sector. Further, the cost of implementing the draft rule is likely to be minimal. The draft rule also retains DNSPs' ability to approach and structure their DAPRs as appropriate.

Overall, the Commission considers that the draft rule would, or is likely to, better promote the achievement of the NEO than the proposed rule. It would do so by balancing efficient network and non-network investments so that electricity is supplied at the lowest overall cost, while maintaining a safe, secure and reliable network. Further details of the Commission's reasons for making the draft rule are set out in chapter 5.

3.5 Consistency with the AEMC's strategic priorities

The rule change request relates to the AEMC's markets and network strategic priority. The markets and network priority recognises the importance of rules that encourage flexibility and efficient investment over time. This strategic priority recognises that non-network solutions to system limitations have the potential to benefit all customers, particularly where non-network solutions reflect consumer preferences.

The draft rule would allow providers of non-network solution to play a greater role in future changes to the network. Where non-network solutions address a system limitation more efficiently than network solutions and are implemented, consumers will benefit from lower costs for the electricity they use.

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49 Kelly, S., Rutovitz, J., Langham, E., McIntosh, L. (2016) *Economic Impact Analysis of Local Generation Network Credits in New South Wales*, Institute for Sustainable Futures, UTS. Access on 26 August 2016 at: https://www.uts.edu.au/sites/default/files/EconomicModellingofLGNC.pdf

50 AEMO, National Electricity Forecasting Report for the National Electricity Market, June 2016.

4 Local generation network credits

This chapter summarises stakeholder views on the rule change request and sets out the Commission's assessment of the rule change request against the criteria in section 3.2.

4.1 Summary of the local generation network credits proposal

The rule change request would require DNSPs to pay all eligible embedded generators a credit that reflects embedded generators' potential to defer or reduce network costs. The rule change request recognises that the NER already provide some incentives for efficient investment in embedded generation. However, it argues that these incentives either do not provide adequate recognition or may not be readily accessible to small-scale embedded generators.[51] Nevertheless, the rule change request proposes that LGNC be paid to all embedded generators, regardless of size.

As proposed, LGNCs would pay embedded generators 100 per cent of the estimated network savings (as measured by LRMC of investment in the network). As such, the proposal would result in no overall network savings for the benefit of consumers. DNSPs would be required to pay LGNCs to embedded generators, and would need to recover those payments through network charges levied on all consumers.

It is more likely that the proposal would, in fact, increase costs for all consumers. This is because the broad nature of the proposed LGNCs would not incentivise efficient investment in embedded generation, meaning that the cost of LGNCs would likely outstrip the value of any deferred or avoided network investment. In addition, DNSPs would incur costs in implementing and operating the LGNC scheme. These additional costs would need to be recovered from consumers through higher network charges. Therefore, the LGNC regime as proposed would not be in the long-term interests of consumers.

The Commission assessed carefully both the proposal and different LGNC arrangements that could form the basis of a more preferable rule. This chapter does not outline alternative LGNC arrangements,[52] but rather assesses whether any LGNC arrangement that meets the broad characteristics described in the rule change request would be likely to contribute to the NEO.

51 See: Rule change request, p. 1

52 One such alternative arrangement considered by the Commission is described in the ISF' report 'Economic Impact Analysis of Local Generation Network Credits in New South Wales', accessed on 26 August 2016 at: https://www.uts.edu.au/research-and-teaching/our-research /institute-sustainable-futures

The broad characteristics include, but are not limited to:

- LGNCs would be paid to embedded generators based on net electricity exports, where the value of an LGNC is linked to the DNSP's estimate of its LRMC[53];
- the value of an LGNC would be revised in the same manner and at the same time that DNSPs revise their consumption tariffs;
- LGNCs would be paid to all eligible embedded generators - the eligibility criteria may be based on the size of the generating unit and when it was connected to the network; and
- the value of an LGNC would be such that network cost savings would be proportioned between the embedded generator and the DNSP.[54]

4.2 Summary of stakeholder submissions

The Commission received 59 submissions on its consultation paper from ten broad stakeholder groups including: consumer representatives, business customers, environmental groups, local and state governments, energy industry associations, DNSPs, generators and retailers, academics and others. The vast majority of submissions rook a clear position either in favour of or against the proposal.[55] Where relevant, stakeholder comments have been addressed throughout this determination. Appendix A summarises issues raised by stakeholders that were not explicitly addressed in the determination, and includes the Commission's responses to each.

Stakeholders who supported the rule change request argued that an export tariff, such as LGNCs, would be a corollary to cost-reflective consumption tariffs, as introduced in the AEMC's rule change.[56] They also argued that LGNCs would discourage consumers from inefficiently investing in batteries and private networks "behind the meter". In turn, LGNCs would result in lower charges to consumers by preserving the utilisation of the distribution network, compared to a situation in which demand for network-supplied electricity falls significantly. Some submissions encouraged the AEMC to consider the results of the ISF's research in this area (see Box 4.1 for a summary of the ISF's findings).

Other arguments made in favour of the proposal are that embedded generation can improve reliability in remote communities, and that LGNCs would address a cultural bias in DNSPs against non-network solutions.

53 The value of the LGNC also includes an estimate of the avoided transmission costs.

54 Through the EBSS and CESS, consumers would benefit from lower charges as a result of any network cost savings.

55 Submissions can be read on the AEMC's website at: http://www.aemc.gov.au/Rule-Changes/Local-Generation-Network-Credits

56 AEMC 2014, Distribution Network Pricing Arrangements, Rule Determination, 27 November 2014, Sydney.

Box 4.1 ISF modelling of the impact of LGNCs

The ISF, at the University of Technology, Sydney has carried out two pieces of research advocating for the LGNC proposal:[57]

- modelling four specific case studies ('virtual trials');[58] and
- modelling the economic benefits across New South Wales ('economic modelling').[59]

Virtual trials

Under the virtual trials research:

- project proponents were examining ways to increase the financial viability of their embedded generation projects; and
- projects were located in areas where there is no system limitation or projected system limitation.

Since there is no system limitation, these projects cannot reduce network costs. As such, any payment of LGNCs would simply increase costs to consumers.

Nevertheless, the ISF assessed the impact of variations of an LGNC payment or private wire investment (moving consumption behind the meter)[60] on the financial viability of the projects.

Its key finding (with relevance to this rule change request) is that DNSPs stand to lose more revenue from the installation of a private wire than if they were to pay an LGNC.

However, if distribution tariffs are cost-reflective, consumer charges would not be affected by a project proponent's decision to build a private wire.[61] This is because any decrease in a DNSP's revenue would reflect the avoided cost of supplying the project proponents and would not impact on the cost of supply the DNSP's other customers.

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57 In addition to LGNCs, the ISF assessed the benefits of local electricity trading. The concept and analysis related to local electricity trading are beyond the scope of the LGNC rule change request.

58 Rutovitz, J., Langham, E., Teske, S., Atherton, A., & McIntosh, L (2016) *Virtual Trials of Local Network Charges and Local Electricity Trading: Summary Report*, Institute of Sustainable Futures, UTS

59 Kelly, S., Rutovitz, J., Langham, E., and McIntosh, L. (2016), *An Economic Impact Analysis of Local Generation Network Credits in New South Wales*. Institute of Sustainable Futures, UTS

60 Installing a private wire would likely reduce the consumption of electricity supplied from the network, but does not represent complete disconnection from the network.

61 Under the Commission's cost-reflective distribution network tariffs rule change DNSPs are required to develop prices that reflect the costs of providing services to individual consumers.

Economic modelling

The ISF's **economic modelling** looks at the cost of meeting peak demand with and without LGNCs, in the period to 2050. The ISF made a number of key assumptions in its modelling, which are critical to its finding that LGNCs have a positive overall impact on electricity costs. The ISF assumes that:

- LGNC payments are only made to new embedded generators - under the rule change request all embedded generators, new and existing, would be eligible for LGNC payments;
- LGNC payments are only made to embedded generators larger than 10 kW - under the rule change request all embedded generators, including solar PV systems would be eligible for LGNC payments;[62]
- the value of LGNCs is set at 80 per cent of the LRMC[63] - the rule change request based LGNCs on the full value of LRMC;
- the network has sufficient capital to meet demand growth until 2025 in the business as usual scenario; and
- peak demand will **increase** by an average of 0.6% per year over the period to 2050 - AEMO's latest forecast in its 2016 National Electricity Forecasting Report is that peak demand will **decrease** by an average of 0.1% per year over the next 20 years.[64]

The ISF's key results are:

- over the short-term (2020) the LGNCs result in a net cost to consumers, but by 2025 there is net benefit;
- more embedded generation due to LGNC payments reduces peak demand and defers network investment by between two and five years; and
- by 2050, the net benefit to consumers (ie the reduction in network costs less LGNC payments) is $66 million per annum above the business as usual scenario.[65]

Those results are based on peak demand growing by 0.6% per year. If peak demand grows by less than 0.2% per year, the ISF finds that LGNCs would cost consumers a net $233 million over the period to 2050.

62 Box 4.3 summarises modelling by Marsden Jacob Associates for the AEMC, which shows that the majority of LGNC payments under the rule change request would be made to residential solar PV.

63 That means that cost savings as a result of LGNCs are shared with the DNSP and, by extension, with consumers.

64 AEMO only publishes demand forecasts out 20 years.

65 The cumulative saving over the period is $1.2 billion.

The ISF's modelling assumptions have a number of limitations that result in an over-estimation of the potential for LGNCs to reduce costs to consumers and evidence the sensitivity of the modelling to these assumptions. The modelling:

- does not account for the practical realities of network planning and investment, including the 'lumpy' nature and locational specificity of network investment;
- does not account for additional network costs associated with:
  - integrating increased levels of embedded generation;
  - implementing and administrating LGNCs;
- fails to account for the operation of the EBSS and CESS, under which 70 per cent of savings would lead to lower consumer charges, with the other 30 per cent being retained by the DNSP.

Given the ISF's modelling assumptions and the resulting over-estimation of the net benefits, a modified form of LGNC may reduce network costs, but it is likely that LGNCs will increase costs in most circumstances.

There was no consensus among stakeholders as to the appropriate level of specificity of LGNCs (for example, the need for locational price differences), nor as to appropriate eligibility criteria (for example, whether existing generators should be able to receive LGNC payments).

The argument raised by stakeholders who oppose the rule change request was that there is no issue that justifies introducing LGNCs. Those stakeholders consider that the NER offers adequate mechanisms to incentivise efficient investment in embedded generation, including some mechanisms that are still being implemented. Further, these stakeholders consider that a broad LGNC would provide an imperfect price signal and risk leading to inefficient investment in embedded generation. Conversely, they consider that it would be disproportionate to have an export tariff (the LGNCs) that is more specific and complex than demand tariffs.

Some stakeholders also argue that the asymmetric design proposed in the rule change request would result in a wealth transfer from consumers to owners of embedded generation, without a reduction in overall network costs. In particular, some stakeholders noted that the NER prohibits DNSPs from charging embedded generators for using the network to export energy, even where the embedded generator increases network costs. As a result, those costs must be recovered by higher network charges for all consumers.

Other arguments made against the proposal are that DNSPs would incur significant costs implementing and administering LGNCs, and that embedded generation (particularly intermittent renewable generation) can have a negative impact on network reliability. Box 4.2 summarises a research project on the potential impact of LGNCs on investment in embedded generation.

Box 4.2 Potential effectiveness of an LGNC price signal

In a supplementary submission on the consultation paper, the City of Sydney retained Oakley Greenwood to examine the potential effectiveness of LGNCs.[66]

Oakley Greenwood modelled the financial impact on consumers with solar PV, with and without a battery. It did so under scenarios in which the customer either:

- does not change their consumption profile;
- reduces their consumption significantly in response to an LGNC and exports all the energy generated; or
- adjusts their consumption profile somewhat in response to the higher opportunity cost of consuming during peak periods when an LGNC applies

Oakley Greenwood finds that the financial benefit to the customer may be material when it exports all its energy, but minimal in the other scenarios. The modelling does not address how any changes in consumption and export profiles may impact on network investment.

Oakley Greenwood also provides anecdotal evidence from Orion Energy in New Zealand, whose export credits are said to be comparable to the LGNC proposal. That evidence highlights how credits can favour one technology over others:

> "'The main influence of our credits has been on large customers that have diesel generation for backup. Our credits have encouraged them to maximise output and in some cases to over-size their generation, and export, rather than just meeting their own load'.[67]"

4.3 Assessment against criteria

This section provides a detailed assessment of the LGNC proposal (including different forms of the mechanism) against the assessment criteria listed in section 3.2.

4.3.1 Specificity

The value provided by any non-network solution depends on location, network system limitations or projected limitations, and the reliability and controllability of the non-network solution. LGNCs could be designed to be very specific and only be paid to an embedded generator when it addresses a specific issue that defers or avoids a planned network investment. However, the more specific the LGNC regime becomes

66 Oakley Greenwood, Potential effectiveness of an LGNC price signal - prepared for City of Sydney, 17 August 2016.

67 Ibid, p. 11

the more complex the implementation and operation of the regime, increasing its administrative costs.

In addition, the more specific LGNCs becomes, the more similar they would be to the existing network support payment and avoided TUoS mechanisms. These mechanisms are in place and incentivise efficient investment in, and use of, embedded generation to reduce network costs.

Data collected by the AEMC indicates that total network support payments and avoided TUoS currently paid to providers of non-network solutions by all DNSPs in the NEM is in the range of $11-13 million. These payments are made to several types of non-network solutions, including embedded generation and demand response. This is a relatively modest amount in the context of total network investment across the NEM. However, that may reflect current spare capacity on large parts of the network and the low current levels of expenditure on network augmentations, reducing the opportunities to avoid network augmentation.

The scale of payments may also reflect the potential limitations of embedded generation in addressing network constraints, given the need to offer firm capacity.[68] From 2011 to 2015, the Victorian DNSPs CitiPower and Powercor made avoided TUoS payments to 18 different embedded generators totally over $10 million. Payments to some individual generators during this period exceeded $ 1 million per year.

On the other end of the spectrum, LGNCs can be designed so that payments are made to a broad range of embedded generators. This would likely be simpler to implement and operate and may cost less to administer.[69] Broad LGNCs would over-signal the need for investment in some areas and under-signal the need for investment in others. As a result, the incentive to locate where network costs can be avoided would likely be too weak, while the incentive to locate where there are no network savings would likely be too strong. The resultant under- and over-investment in embedded generation would lead to an inefficient outcome.

Broad LGNCs may also over-incentivise embedded generation that does not export during the network peak period, or does not provide the required reliability and controllability to avoid investment in the network. Again, this would not lead to an efficient outcome.

The above issues lead to a significant risk that DNSPs would be required to pay LGNCs to embedded generators, but the resulting increase in embedded generation

68 Network support payments are a bespoke mechanism that may be paid when a non-network solution allows the network to defer or avoid network investment. In order to ensure that costs can be avoided, it is necessary for the DNSP to ascertain the location, reliability and controllability of the non-network solution. Where relying on the non-network solution has the potential to reduce network reliability, or increase network costs, the non-network solution is unlikely to be the efficient solution and a network support payment is unlikely to be paid.

69 The relationship between breadth of eligibility, complexity of application and administrative costs is not linear. Broad LGNCs would be paid to more embedded generators, but would be simpler to calculate. The opposite is true for highly specific LGNCs.

would not materially reduce network augmentation costs. The additional costs of LGNCs would need to be recovered from consumers through network charges, and DNSPs would still need to pay for network augmentations. The overall effect would be higher network charges for consumers.

LGNCs may incentivise one embedded generation technology over others. That will be efficient if the level of the incentive reflects the degree to which the embedded generator reduces network costs. However, LGNCs will be less efficient if, as proposed, the payment structure is very broad and payments do not reflect local system constraints.

Controllable generators such as diesel and co-generation would be able to best capitalise on LGNC payments. This is shown in the larger payments for co-generation estimated by Marsden Jacob Associates (see box 4.3). Similarly, a diesel generator, can generally turn on quickly and export electricity during the network peak.[70]

Box 4.3 Modelling the value of LGNCs and LGNC payment

Alongside this draft determination, the AEMC is publishing a report commissioned from Marsden Jacob Associates,[71] who were asked to estimate:

- the unit value of an LGNC that would be paid to owners of embedded generators by each DNSP in the NEM, based on published LRMC values and mirroring the consumption tariffs of each DNSP;
- the total LGNC payments earned over a twelve month period by various types of embedded generation types; and
- the total LGNC payments made by each DNSP over a twelve-month period.

This modelling represents conditions at a single point in time. However, it provides some insight into how the value of LGNCs may be determined and the quantum of payments that may affected

Marsden Jacob Associates estimates the total annual LGNCs paid by all DNSPs to be $50 million, of which around 73 per cent ($36.7 million) would be to households with solar PV.

Individual DNSPs are estimated to pay between $0.2 million (CitiPower) and $10.3 million (Ergon Energy). The following annual LGNC payments may be implied:

- Households with 4KW solar PV - less than $50 in most DNSP pricing zones.

70 Batteries are potentially capable of the same, although they are not currently commercially viable in many cases.

71 Marsden Jacob Associates, Modelling the Value of Local Generation Network Credits - prepared for the Australian Energy Market Commission, Final Report, 2 June 2016.

- Commercial with 20KW solar PV - less than $60 in most DNSP pricing zones, but $580 in Ergon's West pricing zone.
- Distribution-connected 200KW solar farm - from $2,300 in South Australia, Victoria and rural New South Wales to $6,700 in Ergon's East pricing zone.
- Distribution-connected 1MW wind farm - from $11,000-$15,000 in Victoria to $27,000-$28,000 in rural New South Wales and Queensland.
- Co-generation 5MW system - from $105,000 in coastal New South Wales and $129,000 in South Australia to $200,000 in rural New South Wales and Queensland.

Overall, the benefits of specific LGNCs can be achieved at a lower cost through existing mechanisms, and broad LGNCs are likely to result in inefficiently incurred costs. As such, LGNCs are not justified from a specificity perspective.

4.3.2 Proportionality

Good regulatory practice promotes minimal intrusion unless a market failure is identified. Where a market failure is identified, regulation should be as minimal as possible to address the issue at the lowest cost to the market overall. Most stakeholders acknowledge that the existing mechanisms can be effective in situations where embedded generation has the potential to reduce network costs. This means that appropriate intervention should be targeted at the problem - enabling effective access and use of the existing mechanisms.

LGNCs, no matter how designed, are likely to result in significant implementation, administration and operation costs for DNSPs and the AER. For the AER, that involves producing a guideline, and developing an approach that incorporates LGNCs into the regulatory revenue and tariff structure determinations. For DNSPs, costs include:

- developing and consulting on the form of LGNC tariffs;
- collecting the relevant information;
- calculating the LGNC values;
- establishing a register of eligible embedded generators; and
- implementing a payment system.

The efficient costs incurred by DNSPs in complying with the proposed rule would be passed on to consumers through higher revenue allowances set by the AER.

Given that the value of embedded generation is specific to the circumstances, that the proponents identify the issue as only applying to small-scale embedded generators, and that there are mechanisms in the NER, the proposed LGNCs cannot be said to be a proportional response.

4.3.3 Technology-neutrality

The electricity sector is evolving, with an increased take-up of new technologies and the continuing evolution of existing technologies. In this climate of innovation, it is essential the NER do not curtail new solutions, business models or emerging businesses, nor favour one technology over others. For that to be the case, the NER should be agnostic to the technologies that may be used and that are incentivised.

Generally, the mechanisms in the NER are technology-neutral; the same cannot be said about the proposed LGNCs. LGNCs are designed to specifically incentivise embedded generation over any other non-network solution. As a result, LGNCs may result in over-investment in embedded generation at the expense of other, potentially more efficient, non-network solutions. This would be an inefficient outcome.

LGNCs would also be payable to all embedded generators, ie all generators that connect to the distribution network, but would not be payable to any generators that connect to the transmission network. As demonstrated in the Marsden Jacob Associates analysis in box 4.3, relatively large distribution-connected solar farms or wind farms could be eligible for significant LGNC payments. But a transmission-connected generator that had the same impact on network costs would not be eligible to receive any LGNCs. This could result in inefficient outcomes if a generator has a choice of whether to connect to the distribution or transmission network and chose to connect to the distribution network in order to receive LGNC payments when the costs of connecting to the transmission network are lower.

4.3.4 Symmetry

In some circumstances, embedded generation may reduce network costs; in other cases, the DNSP will incur additional costs as a result of embedded generation. For example, high levels of intermittent generation may require transformers to be upgraded in order to ensure the safety and reliability of electricity supply. Where electricity produced by embedded generators exceeds local electricity demand, the DNSP may need to upgrade its assets to manage "reverse power flows". The AER recently allowed Energex $25 million to invest in monitoring and remedying issues caused by high levels of solar PV generation.[72]

Currently, under the NER, embedded generators above a certain size pay for the direct costs of connecting to the distribution network (this is known as 'shallow' connection costs). But DNSPs are not allowed to charge an embedded generator for using the network to export electricity.[73] There are limitations on connection charges for embedded generators below a certain size, meaning that connection costs may exceed charges. That means that all of the capital and operating costs of building and maintaining the network, as well as any difference between connection costs and

72 AER, Final Decision, Energex determination 2015−16 to 2019−20, Attachment 6 − Capital expenditure, October 2015.

73 See: NER clause 6.1.4

connection charges, are recovered from all consumers through general network charges.

An embedded generator will generally receive a benefit from its ability to use the distribution network. For example, where an embedded generator sells electricity in the wholesale market or to a local retailer, it is only able to do so because it uses the distribution network. However, that generator does not pay for using the system.

The rule change request is clear that LGNCs should be set such that embedded generators would be paid for their potential to reduce network costs, but would not be charged where they increase network costs. Consumers would bear the costs associated with both the LGNC payments themselves and any increased costs resulting from incorporating additional embedded generation into the network.

Therefore, the proposed LGNCs cannot be said to be symmetrical - embedded generators receive all the benefits and are not subject to any of the costs. In and of itself, this lack of symmetry does not indicate that an LGNC regime would not, or is not likely to, contribute to the achievement of the NEO. Where the costs incurred by consumers are consistently and predictably less than the overall net benefits, the mechanism may still improve efficiency. However, the costs of LGNCs are likely to outweigh the net benefits, as discussed elsewhere in this chapter.

4.3.5 Cost minimisation

No matter the design of the LGNCs, they are likely to be a costly mechanism to implement and operate despite being designed to address a specific issue.

As drafted in the proposed rule, the rule change request would establish a new payment relationship between DNSPs and embedded generators. Setting that up would require DNSPs and the AER to incur material costs in implementing and administering the mechanism (see section 4.3.2). Even if LGNCs were to be processed by retailers, rather than by DNSPs, there will be material costs in passing these payments through from DNSPs to retailers and from retailers to consumers, and arranging payments to embedded generators that are not also retail customers. These costs would likely result in higher electricity charges for all consumers.

4.4 Conclusion

The Commission is of the view that the proposed rule would not, or is not likely to, contribute to the achievement of the NEO. This is based on both a principled assessment of the proposal (and variations of it) and on an empirical assessment of the relative costs and benefits.

Box 4.4 summarises analysis by AECOM for the AEMC. It shows that, even where there is a projected system limitation, LGNCs are likely to significantly increase costs to consumers while offering little or no deferral of network investment.

AECOM's report focused on solar PV, as the Marsden Jacob Associates report discussed in box 4.3 found that the majority of LGNC payments are expected to be made to solar PV generators. Data from AEMO used in preparing the report shows a projected significant increase in the levels of household solar PV in all NEM jurisdictions. This increase in solar PV is projected to occur under current market conditions - ie even without LGNCs.

Box 4.4 Impact of embedded generation on network planning and network costs

Alongside this draft determination, the AEMC is publishing a report commissioned from AECOM.[74] AECOM was asked to assess how more embedded generation, as a result of LGNC payments, would affect DNSPs' practical decisions to invest in the network.

AECOM considered three zone substations (ZS) on different networks that are expected to face a capacity constraint at different time periods (one within the current regulatory period, one within 10 years, and one beyond 10 years). AECOM specifically assessed situations where an investment need is expected, as these represent the most likely opportunities for embedded generation to reduce network costs.

In the baseline scenario, AEMO's state-based solar PV uptake projections from the 2016 National Electricity Forecasting Report were used to estimate growth in solar PV over a 30-year period. Based on these projections, a significant amount of solar PV is included in the baseline scenario. The LGNC scenario assumed additional solar being installed as a result of LGNC payments.

AECOM assessed how greater take-up of solar PV would affect peak demand at each substation, and whether that would defer the need to augment that part of the network. The value of any such deferral was compared to the cost of LGNC payments to solar PV in the same area.

AECOM used the LGNC starting values calculated by Marsden Jacob Associates, and a profile for how these change over time that reflects a higher value when a constraint is imminent and a lower value once the constraint has been addressed.

AECOM found that, for all three case studies, the level of peak demand reduction with LGNCs was small and insufficient to defer investment in the network beyond that achieved in the baseline scenario. This is despite modelling four different scenarios of additional PV uptake as a result of LGNC payments.

The AECOM results indicated that for all three case studies the cost of paying the LGNC was substantial and outweighed any benefits in the form of deferring the investment need.

74 AECOM, Modelling the Impact of Embedded Generation on Network Planning - report for the Australian Energy Market Commission, 29 August 2016.

Case study	Belconnen ZS	Flemington ZS	Emerald ZS
DNSP	ActewAGL	Jemena	Ergon Energy
Net present cost of LGNC payments	$1.2-1.3 million	$2.0-2.2 million	$17.7-18.7 million
Calculated deferral required to offset LGNC costs	3 years	5 years	LGNC costs are too large to be recovered through any length of deferral
Deferral resulting from LGNCs	None	None	None
Net cost to consumers of LGNCs	**$1.2-1.3 million**	**$2.0-2.2 million**	**$17.7-18.7 million**

The significant uptake of solar PV under the baseline scenario shifts the network peak to later in the day. Ultimately, the peak is projected to shift beyond solar generation hours, at which point additional solar PV would not reduce the level of the peak and would not be able to defer investment in the network.

AECOM also finds that modelling solar PV with batteries has a limited additional effect on deferring network investment, and that any such benefit is still outweighed by the cost of LGNCs.

AECOM's findings must be considered in light of the underlying assumptions, which include only modelling the impact of solar PV, and assuming that future load profiles are consistent with current profiles. AECOM may have under-estimated the net cost of LGNCs since it:

- uses 30-minute increments in the model, which does not fully capture the intermittent nature of solar PV;
- does not include the costs of implementing and administering the LGNC regime; and
- does not include any network costs associated with facilitating high penetration of solar PV.

The result of the three case studies cannot be universally applied to all network investment. However, the results provide a technically-sound indication that increased embedded generation as a result of LGNCs is unlikely to allow a DNSP to defer or avoid network investment. As a result, LGNCs are likely to increase costs for consumers. Further, the high-levels of solar PV take-up, based on AEMO's forecast and without LGNCs, may already be impacting network planning and result in diminishing possible network benefits.

AECOM considered scenarios where there are upcoming system limitations and network investment is forecast. These situations are where LGNCs have the greatest likelihood of reducing network costs and providing an overall benefit for consumers. However, even in these situations, LGNCs were found to have a significant net cost to consumers. In many areas of the network, no system limitations are forecast over the near to medium term and there is no prospect of LGNCs providing a net benefit for consumers. Taken together, the total net cost of LGNCs across all network areas is likely to be even larger than estimated by AECOM.

Analysis by the ISF in support of the rule change request estimates that LGNCs can materially reduce network costs. But that result is only achieved by excluding small-scale embedded generators – the opposite intent to the rule change request – and only if peak demand increases by significantly more than AEMO's latest forecasts.

Taking the results of both reports together, it is likely that, where a system limitation is not projected, LGNCs will lead to higher prices for consumers with no corresponding benefit; and where a system limitation is projected LGNCs are more likely to lead to a net cost than a net benefit. As a result, on balance, the proposal is likely to increase costs to all consumers and would not be in their long-term interest.

5 The draft more preferable rule

This chapter sets out the rationale for the draft more preferable rule and sets out the Commission's assessment against the criteria in section 3.2.

5.1 Summary of the draft rule

In considering the rule change request, the AEMC assessed and consulted on the effectiveness of the existing mechanisms contained in the NER. These include: cost-reflective distribution pricing, network support payments, avoided TUoS payments, reporting and consultation requirements regarding network planning, the CESS and EBSS, the DMIS and DMIA, and the small generation aggregator framework.

These mechanisms are generally effective in incentivising efficient investment in embedded generation. They are targeted to the circumstances in which embedded generation (and other non-network solutions) can reduce network costs. However, stakeholders highlighted that these mechanisms would be more effective if providers of embedded generation and other non-network solution had better and easier access to information about system limitations.

Currently, each DNSP is required to prepare a DAPR that provides information about its plans to invest in the network over a forward planning period of at least five years. Each DNSP must also develop a strategy for engaging with non-network providers and considering non-network options. DNSPs must also maintain a facility by which parties can register their interest in being notified of developments relating to distribution network planning and expansion.

Amongst other things, the DAPR includes information on current and expected system limitations over the forward planning period. It also includes the options that the DNSP is considering to address the limitation. That information, together with DNSPs' other demand-side engagement obligations, is intended to assist providers of non-network solutions to put forward their services as an alternative to investment in the network.

The NER sets out the information that must be included in the DAPR,[75] but does not prescribe the amount of detail that should be included, nor the structure or format for the DAPR. As a result, DNSPs have taken different approaches to their DAPRs, with some including considerably more information than others.[76] For example, Ergon Energy and United Energy both publish maps that shows the parts on their networks where constraints are expected.[77]

75 See: NER, clause 5.13 and schedule 5.8

76 For example, the DAPRs published for the forward planning period 2015/16 to 2019/20 range in length from 110 pages (ActewAGL) to 442 pages (SA Power Networks).

77 See: 'demand management incentive map' on Ergon Energy's website at: https://www.ergon.com.au/network/manage-your-energy/incentives/search-incentives; and 'UE

More information is not necessarily helpful - it is important that information is also clear, accurate, timely and that it can be accessed in a usable format. Stakeholder feedback suggests that there is room for improvement in these regards. The different structures and approaches that DNSPs take to their DAPRs means that providers of non-network solutions find it difficult and resource-intensive to source the relevant information required to put forward a credible alternative to investment in the network in a timely manner.

The draft rule retains DNSPs' ability to approach and structure their DAPRs as appropriate. It supplements the DAPRs by requiring DNSPs to publish in a consistent and usable format information that is either in the DAPR or that they should readily have access to.[78] A few DNSPs already include the information required under the draft rule in their DAPRs.

Under the draft rule, the information that would be contained in the 'system limitation report' is:

- the name or identifier and location of network assets where a system limitation or projected system limitation has been identified;
- the estimated timing of the system limitation or projected system limitation;
- the proposed solution to remedy the system limitation;
- the estimated capital or operating costs of the proposed solution; and
- the amount by which peak demand at the location of the system limitation or projected system limitation would need to be reduced in order to defer the proposed solution, and the dollar value to the DNSP of each year of deferral.

Each DNSP would be required to publish its 'system limitation report' annually together with its DAPR. The template used for the 'system limitation report' would be developed by the AER. It would be developed in consultation with the DNSPs and other parties who have identified themselves to the AER as being interested in the form or content of the system limitation template.

5.2 Assessment against the criteria

This section sets out the Commission's assessment of the draft rule against the criteria listed in section 3.2.

network limitations map 2015' on United Energy's website at: https://www.unitedenergy.com.au /industry/mdocuments-library/

78 The system limitation report will require a DNSP to provide information in relation to the amount by which peak demand would need to be reduced to defer the DNSP's proposed solution and the value of that deferral. Although some DNSP's currently include this in their DAPRs it is not mandatory and, therefore, is a new requirement on the DNSP.

5.2.1 Specificity

A non-network solution may reduce or increase network costs depending on where it is located, its technical impacts on the network and its reliability or controllability. The existing mechanisms in the NER provide incentives or impose obligations on DNSPs to consider non-network solutions, and create opportunities for providers of non-network solutions to address system limitations. The draft rule meets the specificity criterion by supplementing the existing mechanisms.

The 'system limitation report' allow providers of non-network solutions to identify and propose solutions to specific system limitations. In particular:

- Network support payments are more likely to be paid in relation to larger projects, where the cost of addressing the system limitation is above the RIT-D threshold of $5 million. There is a benefit in providing more accessible information about areas where non-network solutions could defer or avoid network expenditure below that threshold, so that providers of non-network solutions could enter into discussions with a DNSP outside of the RIT-D process.

- Some stakeholders consider that the timeframes for proposing a non-network solution as part of a RIT-D process are relatively short. They also consider that the RIT-D process often occurs very close to the date by which the system limitation needs to be addressed, reducing the ability to propose viable non-network solutions that would address the system limitation in the required time. Better information about future system limitations would help embedded generators prepare for an upcoming RIT-D process or approach a DNSP with a proposal for a non-network solution outside of the RIT-D process.

The 'system limitation report' will not be sufficient by itself as the basis for putting up a credible alternative to investment in the network. A provider of non-network solutions would still need to gather additional information (for example, from the DAPR) and discuss the details of the limitation with the DNSP. However, the 'system limitation report' should allow for more constructive engagement between providers of non-network solutions and DNSPs. Ultimately, this can reduce the costs of delivering electricity to consumers.

5.2.2 Proportionality

As explained earlier in this draft determination, the Commission does not agree that the NER do not currently contain sufficient mechanisms to financially reward small-scale embedded generators where they offer an efficient alternative to network investment and reduce network costs.

Rather, the Commission understands that some providers of non-network solutions find it difficult to capitalise on the existing mechanisms because the relevant information is often hard to find or make use of. For example, DNSPs take different approaches to the level of detail and structure of their DAPRs. The draft rule is aimed at addressing this underlying cause of the issue raised in the rule change request.

5.2.3 Technology-neutrality

The NER should provide a consistent but flexible framework that can readily adapt to changing conditions without stifling innovation. The draft rule enables interested parties - be it a new entrant, existing market participant, or new service provider - to more easily ascertain where they may be able to provide an efficient non-network solution, and propose it to the DNSP.

Additionally, stakeholders may find other uses for the information provided in the 'system limitation report' that are of value to providers of non-network solutions, DNSPs and the market more generally. This market-driven innovation should be encouraged, especially where it is reflects consumer choice.

The draft rule does not promote the use of any particular technology or form of non-network solution to address a system limitation. Instead, it makes it easier for providers of any type of non-network solution to leverage the existing mechanisms.

5.2.4 Symmetry

The draft rule promotes efficient investment in embedded generation (and other non-network solutions) where they provide a net benefit in terms of lower network costs. It does not require DNSPs to make payments to embedded generators where they do not provide a net benefit. Nor does it incentivise increased embedded generation in locations where it may lead to net costs for DNSPs that cannot be recovered from the embedded generator and must instead be recovered from all consumers through network charges.

The scope of this rule change process does not extend to potential amendments to existing limitations in the NER on how DNSPs may recover any net costs imposed by certain embedded generators (for example, where connection charges do not fully cover those costs).

5.2.5 Cost-minimisation

Under the draft rule, DNSPs may incur costs in preparing the 'system limitation report'. However, the majority of the information for the 'system limitation report' is already provided in the DAPR, and the remaining information should be readily available or easily determinable given the work required to complete the DAPR. A few DNSPs already include in their DAPRs the information required under the draft rule. As a result, any costs incurred by DNSPs should be small.

The AER may also incur costs in preparing and consulting with DNSPs and other interested parties on the 'system limitation template'. These costs are also expected to be small, given the nature of the task required of the AER.

5.3 Conclusion

The Commission is of the view that the draft rule will, or is likely to, contribute to the achievement of the NEO. The draft rule would help DNSPs and providers of non-network solutions work together to use an efficient mix of network and non-network solutions to address system limitations. In turn, this has the potential to reduce network costs and consumers' electricity prices.

6 Transitional arrangements

Each DNSP is required to prepare and publish its DAPR once a year by 31 December, unless jurisdictional legislation requires the DAPR to be published by some other date.[79] The 'system limitation report' is expected to be completed and published concurrently with each DNSP's DAPR. The Commission intends for the 'system limitation report' to be completed at the same time as the first DAPR published after the final rule's effective date. That is, should the final rule be made in line with this draft determination, it will be implemented so that the first 'system limitation report' is prepared and published by 31 December 2017.

Stakeholders are invited to comment on the following transitional arrangements, which assume that a final rule is made in December 2016:

- the AER must prepare and implement the 'system limitation template' procedure by 1 July 2017; and
- the obligation to prepare a system limitation report will commence on 1 July 2017 such that the first system limitation reports must be published by DNSPs along with their DAPRs in December 2017.

79 See: NER, 5.13.2(a)

Abbreviations

AEMC or Commission	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
DAPR	Distribution Annual Planning Report
DMIA	Demand Management Innovation Allowance
DNSPs	Distribution Network Service Providers
EBSS	Efficiency Benefit Sharing Scheme
ISF	Institute for Sustainable Futures
LGNC	Local Generation Network Credits
LRMC	Long Run Marginal Cost
MCE	Ministerial Council on Energy
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
PV	Photovoltaic
TNSP	Transmission Network Service Provider
TUoS charges	Transmission Use of System Charges

A Summary of issues raised in submissions

Where relevant, stakeholder comments have been addressed throughout this draft rule determination. The table below summarises issues raised by stakeholders that were not explicitly addressed in the body of this report, and provides the Commission's response.

Issue	Stakeholder(s)	AEMC response
Assessment framework		
The National Electricity Objective should take into account environmental and social benefits	City of Sydney; Public Interest Advocacy Centre; Total Environment Centre; Northern Alliance for Greenhouse Action; Ethnic Communities' Council of NSW; Mirvac; Eastern Alliance for Greenhouse Action; Southern Sydney Regional Organisation of Councils	Considering environmental and social benefits is the role of governments. The Commission's interest is in supporting energy market efficiency and the long-term interests of consumers in the context of environmental policies set by governments. The AEMC works with governments in an effort to coordinate energy policy, environmental policy and social policy.
The AEMC should take into account the findings of the ISF's modelling on LGNC 'virtual trials'	City of Sydney; Property Council of Australia; Local Government Infrastructure Services; ISF; Byron Shire Council; Willoughby City Council; Swan Hill Rural City Council; Eastern Alliance for Greenhouse Action; Goulburn Broken Greenhouse Alliance; Mirvac; Australian Energy Council; Sydney Water; Wannon Water; Moira Shire Council	The AEMC worked with the ISF to understand its findings and their relevance to the rule change request. The ISF's modelling is discussed in detail in box 4.1.
The AEMC should take into account the findings of the Essential Services Commission (ESC) of Victoria's 'investigation into the true value of distributed generation'	City of Sydney; Eastern Alliance for Greenhouse Action	The AEMC met with the ESC to understand the relevance of its project to the rule change request. The scope and objectives of the ESC's project are distinct from this rule change request in the following ways:

Issue	Stakeholder(s)	AEMC response
		• The rule change request only relates to the network cost savings embedded generation might bring about; whereas the ESC is also looking at the potential benefits of embedded generation to the wholesale market and environmental benefits. • The rule change request is to introduce LGNCs for all embedded generators, although it is particularly concerned with the impact on small-scale embedded generators; whereas the ESC has limited its review to embedded generation of up to 5MW. • The draft rule changes Chapter 5 of the NER, which also applies in Victoria. If the ESC recommends any new arrangements for embedded generators and the Victorian government adopts these recommendations, they will apply only in Victoria.
The AEMC's assessment framework should include demand-side participation	Ergon Energy; Energy Efficiency Council	The rule change request is clear that it relates only to embedded generation. Nevertheless, in making its draft determination the Commission is mindful of the need for the NER to remain technology-neutral.
Embedded generation in general		
Embedded generation is lower cost and more reliable for remote communities	Local Government Infrastructure Services; Swan Hill Rural City Council; Goulburn Broken Greenhouse Alliance; Bass Coast Shire Council	There are mechanisms in the NER - such as network support payments - to incentivise efficient investment in embedded generation in situations where it represents a lower cost or better value alternative to investment in the network.
Intermittent generation can have a negative impact on network reliability	AusNet Services; Endeavour Energy; Energex; United Energy; GDF Suez Australian Energy; Energy Efficiency Council; Origin Energy	The Commission agrees that embedded generation may result in higher or lower network costs depending on the circumstances.

Issue	Stakeholder(s)	AEMC response
Embedded generators have not been proactive in offering network support services	AusNet Services	The NER provides DNSPs with an incentive to seek the lowest cost solutions to providing their services - be it network or non-network solutions.
DNSPs should be able to control the operation of embedded generators in order to maximise the network support value	Ergon Energy	DNSPs have the ability to negotiate agreements with consumers and provide incentives, including price signals, to promote consumer choice that also maximises the network support value from non-network solutions.
Embedded generation should be included in the incentive-based network regulation framework	CS Energy	Generation in the NEM is a competitive service. The network regulation framework includes mechanisms that incentivise DNSPs and TNSPs to contract with non-network solutions, including embedded generation, when these offer lower costs or greater benefits than network solutions. These mechanisms include the CESS and EBSS, the DMIS and DMIA, and the RIT-D and RIT-T.
Clause 6.1.4(a) of the NER should be changed to allow DNSPs to charge embedded generators for use of the network	Endeavour Energy; Essential Energy; Ergon Energy	This is outside the scope of this rule change request.
As more embedded generation is connected, it will use more 'upstream' parts of the network; any costs imposed at those higher voltage parts of the network would not be recovered from embedded generators because they only pay for 'shallow' connection costs	SA Power Networks	The Commission agrees that embedded generation may result in higher or lower network costs depending on the circumstances. Connection charges are outside the scope of this rule change request.

Issue	Stakeholder(s)	AEMC response
The LGNC proposal		
LGNCs would be a corollary to cost-reflective consumption tariffs	ISF; AGL	The Commission agrees that the proposed form of LGNCs would mirror the design of consumption tariffs. A key question in assessing the rule change request is whether LGNCs are an efficient mechanism that would supplement the existing arrangements, or whether it would duplicate them.
LGNCs would prevent consumers from inefficient investment in batteries and private networks "behind the meter", and would result in lower charges to consumers by preserving the utilisation of the distribution network	ISF; Bass Coast Shire Council; Ethnic Communities' Council of NSW	The ISF's virtual trials show that, even with LGNC payments, certain investments "behind the meter" would still offer a higher return on the investment.[80] Those virtual trials relate to areas where embedded generation would not address a system limitation. As such, LGNC payments in those cases would result in higher networks costs with no possibly of a cost saving. In turn, consumers would face higher energy charges if LGNCs were to be introduced.
The AEMC should model what the future of the energy network with and without LGNCs	Total Environment Centre; ISF; Byron Shire Council; Bass Coast Shire Council	The future of the energy sector should be driven by consumer choice. In making this draft determination, the Commission considered analysis of the likely impact of LGNCs.
LGNCs would address a cultural bias in DNSPs against non-network solutions	Energy Efficiency Council; ISF	LGNCs would be a mandatory payment from DNSPs to embedded generators. They would not incentivise DNSPs to better consider embedded generation as an alternative to investment in the network. The NER contain several mechanisms that incentivise DNSPs use of non-network solutions - these mechanisms are discussed in section 1.2. The draft rule would make it easier for providers of non-network solutions (such as embedded generation) to identify where they offer a benefit, and to put up credible alternatives to investment in the network.

80 Rutovitz, J., Langham, E., Teske, S., Atherton, A. & McIntosh, L. (2016) Virtual trials of Local Network Charges and Local Electricity Trading: Summary Report, p. 22. Institute for Sustainable Futures, UTS.

Issue	Stakeholder(s)	AEMC response
There are mechanisms to incentivise DNSPs to use embedded generation efficiently; cost-reflective distribution pricing and the DMIS are still being implemented	AGL; Ausgrid; Department of State Development, South Australia; Endeavour Energy; Energex; Energy Networks Association; Essential Energy; Jemena (Vic); SA Power Networks; Snow Hydro Limited; Origin Energy; Ergon Energy	The NER contain several mechanisms that incentivise DNSPs use of non-network solutions - these mechanisms are discussed in section 1.2. The draft rule would make it easier for providers of non-network solutions (such as embedded generation) to identify where they can offer a benefit, and to put up credible alternatives to investment in the network.
LGNCs should be broad	ISF	The Commission is of the view that a broad mechanism would not reflect the highly specific impact of embedded generation on network costs. Broad LGNCs would incentivise too much embedded generation in areas where there is spare capacity and network costs cannot be reduced, and too little embedded generation in constrained areas where there is potential to defer or avoid investment in the network. The overall impact would be higher total network costs and, consequently, higher charges for consumers.
A broad LGNC would send an inefficient price signal	AusNet Services; Energex; EnergyAustralia; Energy Networks Association; Essential Energy; Snowy Hydro Limited; Origin Energy; Ergon Energy	The Commission is of the view that a broad mechanism would not reflect the highly specific impact of embedded generation on network costs. Broad LGNCs would incentivise too much embedded generation in areas where there is spare capacity and network costs cannot be reduced, and too little embedded generation in constrained areas where there is potential to defer or avoid investment in the network. The overall impact would be higher total network costs and, consequently, higher charges for consumers.
LGNCs should be specific; however, a specific LGNC would be complex to implement and costly to administer	AGL; APA Group; Department of State Development, South Australia; Endeavour Energy; Energex; Jemena (Vic); Mirvac; GDF Suez (now Engie); Clean Energy Council; Origin Energy	The Commission considered whether the proposed LGNC mechanism could be amended to be made more specific. However, LGNCs would then resemble existing mechanisms such as network support payments. That, in turn, would weaken any justification for introducing LGNCs as an additional mechanism.

Issue	Stakeholder(s)	AEMC response
LGNCs would result in a wealth transfer from consumers without embedded generation to those with embedded generation	AGL; Endeavour Energy; Australian Energy Council	The Commission agrees that if, as proposed, LGNCs pay embedded generators 100 per cent of the estimated network savings (as measured by LRMC) it would result in no overall network savings. DNSPs would be required to pay LGNCs to embedded generators, and would need to recover those payments through network charges levied on all consumers. In that sense, the rule change request would, at best, simply be a wealth transfer to consumers who own embedded generators.
Network charges should reflect partial use of the network; embedded generation is cheaper because it uses less of the network	City of Sydney; Moira Shire Council; Total Environment Centre; ISF; Byron Shire Council; Bass Coast Shire Council; Swan Hill Rural City Council; Ethnic Communities' Council of NSW; Goulburn Broken Greenhouse Alliance; Willoughby City Council; Tasmanian Renewable Energy Alliance; Public Interest Advocacy Centre	This rule change request relates only to future network costs that can be avoided through the use of embedded generation. It does not relate to how network costs that have already been incurred are recovered. The Commission has considered the question of who should pay for existing network assets in its rule to introduce cost-reflective distribution network prices.[81] LGNCs would also be payable to all embedded generators and would not reflect the proximity of the embedded generator to consumers. For example, modelling by Marsden Jacob Associates for the AEMC published with this draft determination estimates that a distribution-connected 1MW wind farm in rural New South Wales would receive an annual LGNC payment of $28,000, while a typical commercial scale solar PV system in central Melbourne would receive about $45 per year.
LGNCs would enable peer-to-peer electricity trading	ISF; Centre for Energy and Environmental Markets, University of NSW	The proposal is not about enabling peer-to-peer electricity trading. Efficient allocation of network costs is a prerequisite for peer-to-peer trading; but this can be achieved without LGNCs. LGNCs would simply mean that customers without embedded generators would pay higher network charges to fund payments to customers with embedded generation.
LGNCs would support the transition to renewable energy	Wauchope Solar; Solar Energy Industries Association	The proposal is not about encouraging a move towards more renewable generation. The proposed LGNCs would be available to all types of

81 AEMC 2014, Distribution Network Pricing Arrangements, Rule Determination, 27 November 2014, Sydney

Issue	Stakeholder(s)	AEMC response
		embedded generators. Controllable diesel and gas-fired generators would be likely to receive larger payments than solar PV or wind generators of a similar size under on the proposed mechanism. This is because they are more likely will be generating electricity at times of network peak demand.
The discount rate applied to future network cost savings in calculating LGNCs should be capped	City of Sydney; Goulburn Broken Greenhouse Alliance; Moira Shire Council; Swan Hill Rural City Council	There is no economic rationale for capping the discount rate.
To incentivise DNSP participation in the LGNC scheme, they should be allowed to retain a part of the network cost savings	City of Sydney, Tasmanian Renewable Energy Alliance; Centre for Energy and Environmental Markets, University of NSW	It is unclear how allowing DNSPs to retain a part of the network cost savings can be achieved while reducing overall consumer charges.
Current LRMC values (and, consequently, LGNC values) are artificially low because of past overinvestment in the network	Property Council of Australia; ISF; Southern Sydney Regional Organisation of Councils	LRMC values reflect the network cost of meeting future demand. Where a network is not likely to be constrained from meeting higher demand, these costs are likely to be low.
The time-frame for calculating the value of LGNCs should be long-term (ie 10-20 years).	City of Sydney; Goulburn Broken Greenhouse Alliance; ISF; Swan Hill Rural City Council; Willoughby City Council; Moira Shire Council	The time-frame for LRMC calculations for distribution charges (which, according to the rule change request would also be used for LGNC values) will be determined in accordance with the Tariff Structure Statement process under the Commission's distribution pricing rule change.[82]
Non-network solutions and existing NER mechanisms and schemes		
Proponents of non-network solutions find it difficult to engage with DNSPs, particularly if trying to negotiate network support payments or avoided TUoS payments	Mirvac; ISF; Central Irrigation Trust; APA Group	The draft rule would offer providers of non-network solutions the information required to engage constructively with DNSPs.

82 AEMC 2014, Distribution Network Pricing Arrangements, Rule Determination, 27 November 2014, Sydney

Issue	Stakeholder(s)	AEMC response
DNSPs should publish regular information about network constraints and planning	Energy Australia	DNSPs are currently required to do so through their DAPRs.[83] The draft rule will also provide usable, consistent and accessible information to supplement the DAPR.
The current threshold of the RIT-D ($5 million) is too high to capture many of the situations in which embedded generation can displace network investment	Northern Alliance for Greenhouse Action; Centre for Energy and Environmental Markets, University of NSW	The Commission considered changing the RIT-D threshold as one of the potential alternative solutions for the issue raised in the rule change request.[84] The draft rule would make it easier for providers of non-network solutions to propose alternatives to network investment outside the RIT-D.
Price signals		
Zonal or locational network pricing is required to provide appropriate pricing signals and encourage efficient use of network assets	GO Energy; Centre for Energy and Environmental Markets, University of NSW	The Commission's rule to introduce cost-reflective distribution pricing allows for locational charges.[85] However, benefits need to be considered against the costs and consumer impacts of undertaking highly specific pricing.

83 AEMC 2012, Distribution Network Planning and Expansion Framework, Rule Determination, 11 October 2012, Sydney

84 This was discussed with stakeholders at a workshop held 15 March 2016. For a summary of the discussion, see the AEMC website:http://www.aemc.gov.au/Rule-Changes/Local-Generation-Network-Credits

85 AEMC 2014, Distribution Network Pricing Arrangements, Rule Determination, 27 November 2014, Sydney

B 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.

B.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 proposed by the City of Sydney, the Total Environment Centre and the Property Council of Australia.

The Commission's reasons for making this draft rule determination are set out in sections 3, 4 and 5.

A copy of the more draft more preferable rule is published with this draft rule determination. Its key features are described in section 5.1.

B.2 Power to make the rule

The Commission is satisfied that the draft more preferable rule falls within the subject matter about which the Commission may make rules. The more preferable draft rule falls within section 34 of the NEL as it relates to "the activities of persons (including Registered participants) participating in the national electricity market or involved in the operation of the national electricity systems".[86]

B.3 Power to make a more preferable rule

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

As discussed in Chapter 3, the Commission has determined to make a draft rule, which is a draft more preferable rule.

B.4 Commission's consideration

In assessing the rule change request the Commission considered:

- the Commission's powers under the NEL to make the rule;
- the rule change request;

86 NEL s. 34(1)(a)(iii)

- submissions received during the first round of consultation;
- modelling undertaken by the proponents, interested parties and the Commission; and
- the Commission's analysis of the ways in which the proposed rule will or is likely to, contribute to the NEO. This analysis included an assessment against the criteria outlined in section 3.2 of this draft rule determination.

There is no relevant Ministerial Council on Energy (MCE) Statement of Policy Principles.[87]

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 AEMO's declared network functions.[88] The more preferable draft rule is compatible with AEMO's declared network functions because it only concerns distribution networks and does not affect AEMO's declared network functions.

B.5 Civil penalties and conduct provisions

The draft more preferable rule does not amend any clauses that are currently classified as civil penalty or 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 more preferable rule be classified as civil penalty or conduct provisions.

87 Under section 33 of the NEL the AEMC must have regard to any relevant MCE statement of policy principles in making a rule. The MCE is referenced in the AEMC'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.

88 See section 91(8) of the NEL.