04 February 2016

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Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Dear Sir/Madam

RE: ERC0191

Please find enclosed a submission from the Institute for Sustainable Futures at the University of Technolgy Sydney on the proposed National Electricity Amendment (Local Generation Network Credits) Rule 2015. Thank you for the opportunity to make this submission.

The introduction of a local network charge, delivered as a Local Generation Network Credit (LGNC), is an important measure to improve the NER and make it more fit for the electricity system of the future. As you know, ISF is currently leading a one year ARENA project investigating local network charges and virtual net metering, due to finish in August 2016.

Our key concerns are outlined briefly below.

- The consultation timeframe should be adjusted to ensure that the AEMC and other stakeholders can take account of the results from the ISF project,
- The assessment framework should be modified to include
    - Whether consumers should pay a reduced charge for partial use of the electricity network, and whether an LGNC is a suitable implementation method.
    - Whether an LGNC will help maintain utilisation of the distribution network, and the consequent effects on the long term costs for consumers.
    - Potential incentives for inefficient duplication of network infrastructure under the current NER, including costs borne by parties other than network businesses.
- A timeframe of 15 – 20 years should be used to assess the effects of an LGNC on network costs and on consumers, rather than a single regulatory period.

Regards

SWhite

Professor Stuart White
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UTS: INSTITUTE FOR SUSTAINABLE FUTURES
FEBRUARY 2016

Submission to AEMC on ERC0191: National Electricity Amendment (Local Generation Network Credits) Rule 2015

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ABOUT THE AUTHORS

The Institute for Sustainable Futures (ISF) was established by the University of Technology Sydney in 1996 to work with industry, government and the community to develop sustainable futures through research and consultancy. Our mission is to create change toward sustainable futures that protect and enhance the environment, human well-being and social equity. We seek to adopt an inter-disciplinary approach to our work and engage our partner organisations in a collaborative process that emphasises strategic decision-making.

For further information visit: **www.isf.uts.edu.au**

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ACKNOWLEDGEMENT

ISF would like to thank the partners and sponsors of the project Facilitating Local Network Charges and Virtual Net Metering.

DISCLAIMER

The authors have used all due care and skill to ensure the material is accurate as at the date of this report. UTS and the authors do not accept any responsibility for any loss that may arise by anyone relying upon its contents.

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LIST OF ABBREVIATIONS

AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
Capex	Capital expenditure
DUOS	Distribution use of system
EG	Embedded generation
ISF	Institute for Sustainable Futures
kW	kilowatt
LET	Local Electricity Trading
LGNC	Local Generation Network Credit
LNC	Local network charge
LRMC	Long run marginal cost
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
Opex	Operational expenditure
PV	Photovoltaic
Repex	Replacement expenditure
TEC	Total Environment Centre
TOU	Time of use
TUOS	Transmission use of system
UTS	University of Technology Sydney

EXECUTIVE SUMMARY

The Institute for Sustainable Futures (ISF) is leading an ARENA funded research project *Facilitating Local Network Charges and Virtual Net Metering*, finishing in August 2016, to investigate **local network charges** for partial use of the electricity network, and **Local Electricity Trading (LET)** between associated customers and generators in the same local distribution area. The project team brings together a wide range of stakeholders, including proponents, network businesses, and electricity retailers.

Consultation timeframe

The AEMC review of the Rule Change Proposal for a Local Generation Network Credit (LGNC) should consider the results of the ISF project, which include case study evidence from five virtual trials of the mechanisms, a local network credit methodology, and economic modelling of the effect on consumers. The project is the first quantitative testing of the mechanism in the Australian market, and results are therefore highly relevant to the Rule Change determination. ISF is concerned that the published timeline does not allow for adequate consideration of the project results by the AEMC or other stakeholders.

LGNC as a mechanism to deliver reduced charges for partial network use

The proposed LGNC is fundamentally a mechanism to deliver appropriate charges for partial use of the network and reward network benefits provided by local generation. The Consultation Paper does not sufficiently describe the objectives of the Local Generation Network Credit, which are:

- To ensure that consumers and generators are charged appropriately for partial use of the electricity network;
- To incentivise local generation when this reduces network congestion;
- To de-incentivise the duplication of infrastructure, including private wires and generation/ storage systems, set up to avoid network charges altogether; and
- To offer an effective alternative to load defection, in order to maintain utilisation of the existing electricity network infrastructure.

The proposal stipulated a credit to the generator because of the significant complications involved in implementing a reduced charge on consumption. Consideration of the Rule Change proposal should include assessing whether the current charging arrangements for partial usage are equitable, and whether an LGNC is an improvement.

The assessment framework is inadequate

ISF considers the current assessment framework is not adequate to determine whether the rule change meets the NEO, and should be expanded to include consideration of:

1) Whether consumers should pay reduced charges for partial use of the network, and whether an LGNC is an effective means to implement such reduced charges.
2) The effectiveness of the LGNC to maintain utilisation of the distribution network, and the consequent effects on the long term costs for consumers. It is suggested that the framework includes modelling of the system costs per consumer with and without an LGNC.

3) Duplication of infrastructure and the costs that are borne by parties other than Network providers who may be incentivised under the current NER to inefficiently invest in generation, storage or private wires.

A timeframe of 15 – 20 years should be used to assess the effects of an LGNC on network costs and on consumers, rather than a single regulatory period. Savings from the LGNC are likely to arise from long term avoided growth, rather than imminent constraints.

The current NER will not provide appropriate price signals for efficient EG

The Institute welcomes a range of regulatory changes for embedded generation in recent years. However, the current market structure disproportionately incentivises behind the meter generation.

While moves towards cost reflective pricing are to be welcomed, they will not incentivise export of local generation at times of high network demand. Cost reflective pricing in the absence of a local export price signal (such as an LGNC) may in fact provide perverse incentives to invest in additional behind the meter generation and/or storage infrastructure, and increase the risk of customer disconnection in future years. An LGNC may be considered for exports what cost-reflective pricing is for consumption.

Network support payments are case by case, contractual payments to defer imminent network investment. An LGNC fulfils a different function, and is intended as a complementary measure.

An LGNC should reduce the amount consumers pay in the long term

Overall ISF considers an LGNC is likely to reduce the price consumers pay for electricity compared to what they would otherwise pay. There are two aspects to this reduction.

Firstly, savings in augmentation, operational and replacement costs should occur in the long term, as EG will reduce underlying demand.

More complex are consumer savings that may occur because an LGNC maintains utilisation of the distribution network. If load goes behind meter, whether because of additional generation, storage, or a private wire, there is a reduction in charges paid to the network business. If instead the generation is exported and an LGNC paid, the reduction in network charges paid is considerably less. In effect, an LGNC maintains a revenue stream for the network business, compared to the behind the meter alternative. Maintaining utilisation means legacy network costs are shared between more users, reducing future price pressure.

The NER needs to operate the network in the electricity system of the future in the interests of consumers. This system will certainly have much higher penetration of EG. As such it would be prudent for the AEMC to test whether an LGNC has the effect of keeping more of that generation utilising the distribution network, and how this effects consumers.

Potential Misinterpretations in the Consultation Paper

ISF is concerned about some potential misinterpretations of the intent or functioning of the proposed LGNC in the consultation paper. These include:

- The suggestion that a LGNC would require new payment relationship between network businesses and local generators. We expect the retailer to manage the LGNC tariff as a pass through, as is the case with all network tariffs.

- The interpretation that large wind farms would qualify for a LGNC. Generators above 50MW would very rarely be connected to the distribution network.
- The interpretation that technology neutrality means that all generator types would receive LGNCs regardless of availability, whereas the rule change proposal suggests that the LGNC should be *performance* based.

INTRODUCTION

RELEVANCE OF CURRENT ISF PROJECT TO THE RULE CHANGE PROPOSAL

Project summary

The one year ISF-led research project *Facilitating Local Network Charges and Virtual Net Metering*[1], which started in June 2015, brings together a partnership of consumers, researchers, electricity providers and government to help level the playing field for local energy and prepare for the electricity grid of the future. The project is investigating two measures: reduced **local network charges** for partial use of the electricity network, and **Local Electricity Trading (LET)** between associated customers and generators in the same local distribution area. The combination of local network charges and LET aims to offer desirable alternatives to customers who might otherwise choose to disconnect from the grid altogether or keep all their generation "behind the meter", reducing the amount of electricity they take from the grid.

The rule change request that is the subject of the AEMC consultation and this submission, proposes the introduction of a payment from distribution networks to embedded generators as a Local Generation Network Credit. This is in effect a **local network charge**, delivered as a credit via the generator rather than directly to the consumer of the electricity.

Figure 1 The 'virtual' trials

Project aims and outputs

The objective of the ISF project is to create a level playing field for local energy and address current inequitable charging arrangements, by facilitating the introduction of local network charges and Local Electricity Trading. The key outputs are:

a. Improved stakeholder understanding of the concepts of local network charges and Local Electricity Trading;
b. Five 'virtual trials' of local network charges and Local Electricity Trading (see Figure 1);
c. Economic modelling of the benefits and impacts of local network charges and Local Electricity Trading;
d. Development of a recommended methodology for calculating local network charges;
e. An assessment of the metering requirements and indicative costs for the introduction of Local Electricity Trading, and consideration of whether a second rule change proposal is

[1] The ISF project is funded by ARENA and other project partners

required to facilitate its introduction; and

f. Support for the rule change proposal for the introduction of a Local Generation Network Credit submitted by the City of Sydney, the Total Environment Centre, and the Property Council of Australia.

AEMC Determination should take into account the project results

The ISF project is due to be completed in August 2016 and preliminary results from the trials and economic modelling are expected to be available by the end of March 2016. The project is the first of its kind that systematically tests the application of local network charges in the Australian context. The project incorporates extensive background research and consultation with stakeholders, including on the development of an appropriate methodology for calculating a local network charge.

The results of the trials and the economic modelling will demonstrate the financial costs and benefits of local network charges (applied as an LGNC) from the perspective of local electricity generators, network service providers and the whole of society. The project will also make a detailed recommendation on a methodology for calculating the local network charge, which is fundamental to the successful introduction of a LGNC.

It is clear from the project objectives that it is highly relevant to the rule change proposal consideration, and we believe that the outputs and results from the project should be a core element of AEMC's considerations in making a draft and final determination on the LGNC rule change proposal.

WHY THE RULE CHANGE MATTERS

Changing times and the advent of 'prosumers'

The traditional model of one-way flows of electricity from large centralised energy generators to consumers is changing. Over the past decade, electricity prices have doubled, solar PV costs have more than halved, and policy mechanisms have supported renewable energy and energy efficiency measures. Well over a million small residential customers in Australia now have solar photovoltaic (PV) installed on their homes. This has created a significant and growing class of consumer – the *pro*ducer and con*sumer* or 'prosumer' – who both draw electricity from the grid, and export electricity to it.

The current charging structure in the National Energy Market (NEM) in Australia reflects the historic reality of one-way flows via the transmission and distribution networks to the customer. This model has little flexibility to cater for today's prosumer, who is interested in partial use of the distribution system, or to incentivise behaviour that can reduce electricity costs for everyone. The potential benefits of local energy generation may not be realised unless charging structures are modified to suit new technologies and customer expectations.

Dropping demand and the 'death spiral'

After nearly 30 years of continuous growth in Australia, electricity consumption and demand are dropping. Energy efficiency, local energy, varying economic times, and electricity price rises, have resulted in changing patterns of both energy consumption and peak demand.

This downward trend in centralised grid electricity consumption could increase prices further, pushing consumers to reduce consumption even more or disconnect from the grid entirely. This self-perpetuating pattern of upward pressure on prices and downward pressure on consumption is known as the 'death spiral' for electricity networks. It could lead to socially inequitable outcomes as those consumers remaining dependent on centralised electricity sources pay higher and higher prices. This will be exacerbated as disruptive technologies become available to prosumers, in particular battery storage and electric vehicles.

Enabling local energy benefits customers and networks

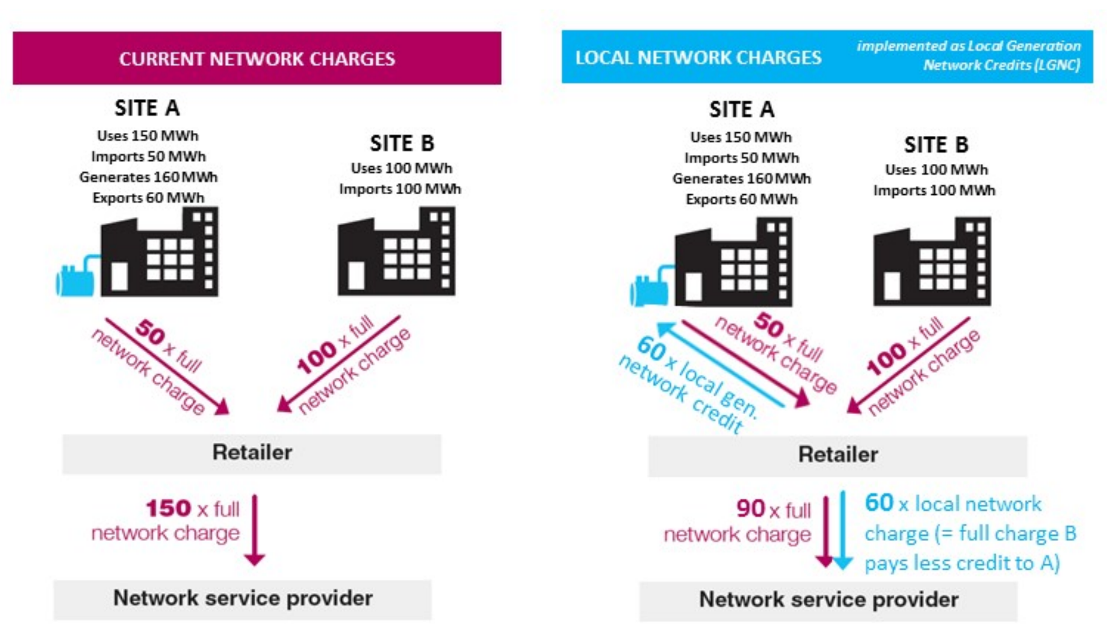
Enabling local energy could help to reduce load defection, i.e. reducing consumption of grid electricity by generating entirely behind the meter, and grid disconnection. Prosumers with their own generation and/or energy storage who may otherwise find it economic to leave the grid could instead trade energy and services to others on the grid and in the local area. This would benefit electricity consumers because prices remain lower as more customers remain on the network, local generators and prosumers because the network continues to provide regulation and back-up services, and network businesses because their customer and revenue base is maintained and the long term need for augmentation is reduced.

Local network charges and local electricity trading are intended to make local energy projects more economically viable, incentivise prosumers to stay connected to the grid, and incentivise the provision of useful grid services from local generation.

HOW AN LGNC MAY WORK

The consultation seeks to present how an LGNC may work, and how this would affect consumers. In order to assist this process, this paper gives an introduction to the monetary flows involved in an LGNC payment, and how this may compare to business as usual.

Figure 2 How an LGNC might work



As shown in Figure 2, the LGNC would be paid to the generator at Site A for exports, according to the tariff developed by network service business. The specific value will depend on the calculation methodology, but would always be less than the network charge paid by the consumer of that electricity at Site B.

The effect of the LGNC is a lower network charge for electricity generated within the distribution area:

[local network charge] = [full network charge] – [local generation network credit]

In the case where Site A and Site B are a single entity, the reduced network charge is delivered to the consumer. In cases where Site A and Site B are different entities, it is assumed (although not required) that the reduced network charge is passed on to the consumer via lower price for the exported energy.

The Consultation Paper states: *"LGNCs would be a separate negative network tariff, and would create a new payment relationship between DNSPs and embedded generators."* (Summary p.i)

The LGNC would not create a new payment relationship, but would mirror existing payment relationships. It is assumed that the retailer would pass through the LGNC payment to generators in the same manner that the retailer also passes through network charges to both generators and consumers. There is precedent in Australia already for this with both Ausnet and ActewAGL providing payments for generation received:

- Ausnet provides a summer generation payment to generators[2]
- ActewAGL makes a payment to some local generators based on an estimate of avoided TUOS. ActewAGL's payment is however not technology neutral and applies only to particular classes of generation unit[3]

THIS SUBMISSION

The submission first discusses the assessment framework in Section 1, which we consider should be altered.

Sections 2 to 6 address consultation questions 2 to 6.

Section 7 makes specific comments on aspects of the consultation paper which are not covered elsewhere in the body of the submission, and we think may be misleading about the purpose of the LGNC or the current arrangements for EG.

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[2] Ausnet. (2015). *Ausnet Annual Tariff Proposal 2015 (Vol. 14).* Retrieved from https://www.aer.gov.au/sites/default/files/Annual Tariff Report 2015 Approved_0.pdf

[3] ActewAGL. (2015). *ActewAGL Electricity Network Prices 2015 - 16.* Retrieved from http://www.actewagl.com.au/~/media/ActewAGL/ActewAGL-Files/About-us/Electricity-network/Electricity-network-prices/Electricity-network-prices-2014-15.ashx?la=en

1 ASSESSMENT FRAMEWORK

Q1.1. Would the proposed framework allow the Commission to appropriately assess whether the rule change request can meet the NEO?

ISF considers that the current assessment framework is not adequate to determine whether the rule change meets the NEO as:

1) The rule change proposal is for a Local Generation Network Credit, which is a mechanism to deliver appropriate charges for partial use of the network as well as to reward network benefits provided by local generation. The assessment framework does not include this aspect of the Credit, and therefore cannot adequately assess whether the rule change is in the long-term interest of consumers.

2) The assessment framework used by the AEMC should consider the effectiveness of the LGNC to maintain utilisation of the distribution network, and the consequent effects on the long-term costs for consumers. It is suggested that the framework includes modelling of the system costs *per consumer* and not simply total network costs, in the absence of an LGNC and with an LGNC.

3) The assessment framework suggests a single regulatory period as the appropriate time frame for considering network cost impacts, and presumably also the impact on consumers. This is not a sufficient time frame, and may result in inefficient investment outcomes, as it does not allow augmentation and non-network options to be compared equitably. In addition, the potential benefits to consumers of an LGNC include maintaining network utilisation over the long term would require a framework of 10 – 20 years at least.

1.1 FRAMEWORK SHOULD CONSIDER LGNC MECHANISM TO DELIVER REDUCED NETWORK CHARGES

The Local Generation Network Credit should be considered as a mechanism to deliver a reduced network charge for partial usage of the network, as well as a mechanism to reward network benefits

The rule change proposal is for a Local Generation Network **Credit** (LGNC). However, the Local Generation Network Credit is fundamentally a practical mechanism to deliver appropriate network **charges** for local energy and to address the current inequity in **charging** arrangements. That is, where consumers pay the same network charges regardless of whether the electricity consumed is purchased from a generator 100m away or 250km away.

This is because the current rules and charging mechanisms were established when the NEM comprised overwhelmingly central generators with one way flows to the customer, i.e. before the onset of widespread access to embedded generation. Thus consumers are paying inappropriately high charges for partial service, which will, in the long term lead to inefficient outcomes.

The decision to implement the mechanism as a credit to the generator, rather than as a reduced charge to the consumer of the energy, was taken primarily for ease of implementation.

It is important that the rule change proposal is considered for its function to deliver appropriate charges for partial use of the network by local generators, as well as to reward network benefits.

In our view the Consultation Paper does not sufficiently describe the objectives of the Local Generation Network Credit, which are:

- To ensure that consumers and generators are charged appropriately for partial use of the electricity network;
- To incentivise local generation when this reduces network congestion;
- To de-incentivise the duplication of infrastructure (private wires) set up to avoid network charges altogether; and
- To offer an effective alternative to load defection, in order to maintain utilisation of the existing electricity network infrastructure.

The Consultation paper makes reference to this in Section 3.3 but unfortunately appears to misunderstand the intention to deliver a reduced charge for partial use of system, and therefore the appropriateness of the term ‘credit’:

“It is worth noting that, although the LGNC it is described as a credit, it does not reflect what is generally understood by this term. Specifically, the term credit could be taken to mean that the effect of the rule change is to reduce the net amount that embedded generators who consume and export electricity pay for their consumption. Rather, the proposal would set up an entirely new payment relationship – between DNSPs and all embedded generators – that is not linked explicitly to any existing bill.”

This note does not acknowledge the relevance of the local **user’s** consumption of the exported energy, as distinct from the local generator’s consumption. The local energy user currently pays full transmission and network fees for energy that is in fact drawn from a local source. The LGNC is indeed a rebate of the inappropriate TUOS and DUOS that would otherwise be paid in the sum of transactions from a local generator and consumer.

The provision of the Local Generation Credit applied as a reduced charge to the consumer was investigated prior to submission of the rule change proposal in a consultation paper and series of workshops conducted by ISF on behalf of the City of Sydney in 2014[4]. While there were attractive aspects to delivery as a reduced charge, significant issues were identified with this approach, primarily regarding impracticality of implementation. Delivery via a reduced charge would require the DNSP (or retailer) to track which local consumers are contractually associated with which local generators, and undertake time of use reconciliation to determine the proportion of their bills which should attract the reduced charge DUOS and TUOS charges. For these reasons it was decided that it would be administratively easier to apply the reduced charge as a credit to the generator.

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[4] See Rutovitz, J, Langham, E., & Downes, J. (2014). *A level playing field for local energy.* Issues paper prepared for the City of Sydney. Institute for Sustainable Futures, UTS.

1.2 FRAMEWORK SHOULD INCLUDE EFFECTIVENESS OF LGNC AT MAINTAINING NETWORK UTILISATION

The assessment framework should include the effectiveness of the Local Generation Network Credit in maintaining utilisation of the distribution network, and the consequent amelioration of cost increases for non-generation consumers.

The current charge structure under the NER strongly incentivises behind the meter generation, as such generation avoids all variable network charges as well as the retail components of the energy charge. Once a local generator uses the network – even if between two meter points in the same premises – full network charges are incurred.

This failure in the NER is likely to exacerbate the trend of declining network utilisation, and reinforce existing perverse incentives to duplicate infrastructure, where it is more cost effective for new developments to aggregate consumption on private embedded networks behind a single HV metering point. Both impacts would result in higher costs for consumers who do not have access to self-generation options. Through incentivising local exports and thereby maintaining utilisation, the rule change under consideration is the only current proposal seriously addressing this major issue. A LGNC would help to harness the creative force of the market to find ways to utilise the local network to connect customers, rather than to find new ways to go behind the meter.

While there is considerable difference of opinion about when battery storage plus local generation is likely to compete with grid-transported electricity, it is almost certainly going to occur within the lifetime of current grid assets. In the absence of charging mechanisms that deliver lower prices for partial use of the network, those consumers who do not have access to self-generation may be left paying a disproportionate share of network costs as consumers who may generate their own electricity reduce their loads accordingly.

Thus it is important for the assessment framework used by the AEMC to include modelling of the system costs per consumer with and without an LGNC, in order to assess whether such a credit is in the interest of consumers.

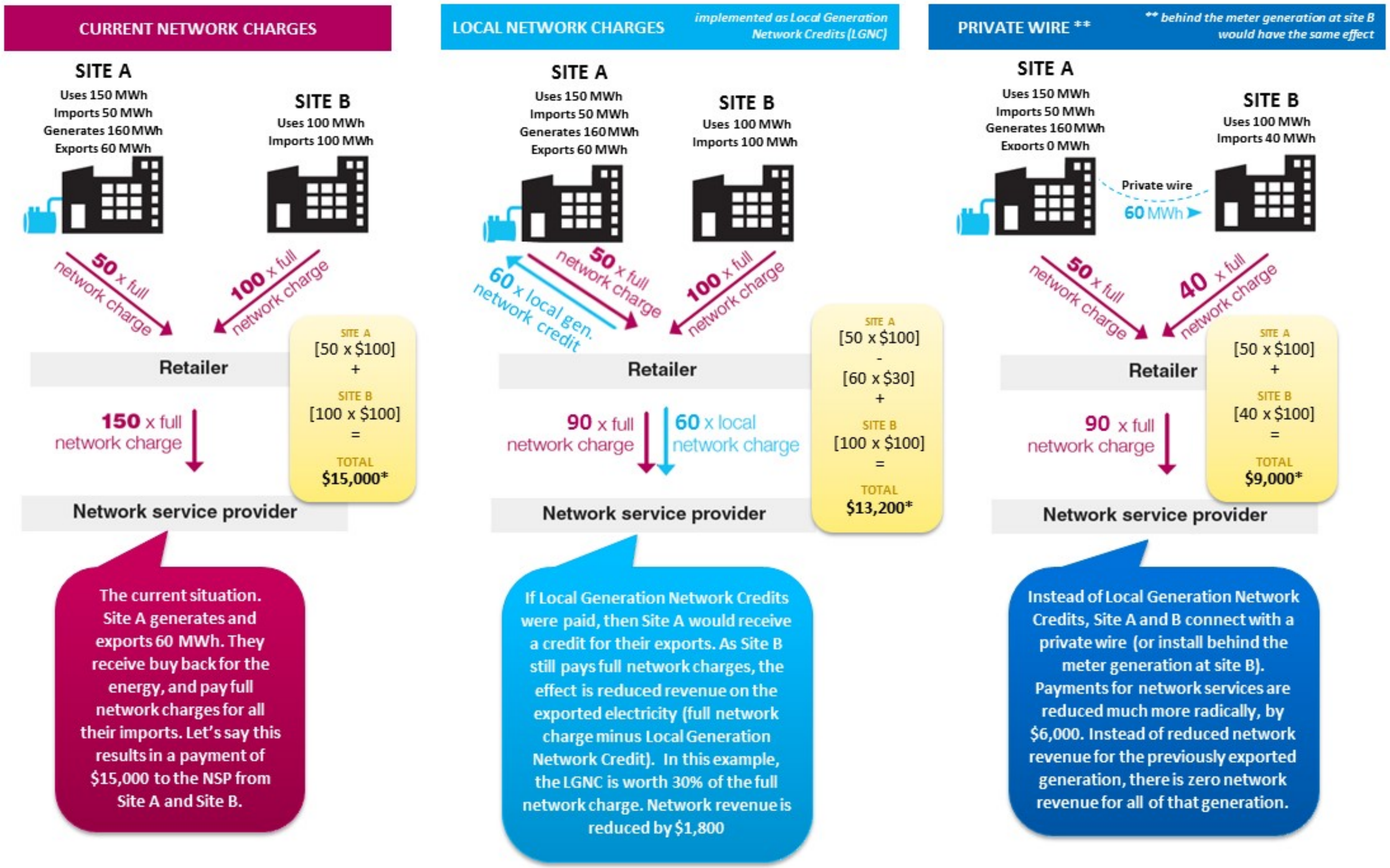
This is particularly evident when the case with an LNC payment is compared to those situations where a private wire installation is either currently economic, or may become so in the near future.

Figure 3 illustrates the network charges paid by the generator / customer combination under current rules, with an LGNC, and with a private wire. However, while a private wire is the most extreme case, this third case also applies to behind the meter generation at Site B.

In this simplified example the hypothetical network charge is $100/MWh and the LGNC value has been taken as 30% of the full network charge. In reality, we would expect the LGNC to take account of the time of export, so all exports would not receive the same value of credit. Site A exports 60 MWh, which is consumed at Site B. There are three scenarios:

Scenario 1. In the current rules case, Site A and Site B combined pay $15,000 in network charges, which are passed through to the network business.

Figure 3 Money flows: current, LGNC, and private wire compared



* Illustrative figures only – full network charge at calculated $100/MWh, and LGNC at $30/MWh (i.e. 30% of full network charge). In fact both charges are a mix of volumetric and capacity, and will depend on time of use.

Scenario 2. In the LGNC case, a credit of $1,800 is paid to Site A for exports, so the combined payments to the network business are reduced by $1,800.

Scenario 3. In the case where a private wire or additional behind the meter generation[5] is installed at Site B, the two sites pay a total of $9,000 in network charges, an overall reduction of $3,000 in network charges.

The reduction in load on the network as a whole and any associated reduction in network costs are identical in Scenario 2 and Scenario 3. If the LGNC methodology is calculating network benefit correctly, the LGNC payment should be equal to network savings in the long term, as it is calculated based on the long run marginal costs of the network (see section 3 below for discussion of network costs savings)**.** In fact, provided the LGNC methodology is well designed, cost savings in the LGNC scenario are likely to be somewhat greater than in the private wire/ behind the meter scenario, as the LGNC will incentivise export at times when it is most useful.

However, regardless of whether the LGNC payment is equal to the network savings, the scenario with the LGNC is better for all consumers in the long run. In Scenario 3, where load goes behind the meter, there is a 40% reduction in network charges paid by the two customers, compared to a 12% reduction in Scenario 2 where the LGNC is paid.

As the network cost savings are identical in both cases, consumers not associated with the transaction are better off when the LGNC is paid, as any shortfall in network charges compared to costs will be spread over all consumers. In general, decreasing grid utilisation will result in increasing network costs per kWh transported, and per customer, creating a feedback look that further reduces grid utilisation.

The consumers associated with the transaction may also be better off in the LGNC case, as the reduction in network charges in Scenario 3 (private wire or additional generation) is associated with additional capital spend on private infrastructure, either in the form of a private wire or additional generation. This is unsurprising, particularly in the private wire case, as the reduction in network costs is simply funding duplication of infrastructure.

While the numbers in this example are hypothetical, they are borne out by preliminary results from the virtual trials of the LGNC and Local Electricity Trading. Summary results from these trials will be available by early April.

The AEMC assessment framework should address the issue of maintaining grid utilisation, and the fact that the rules currently incentivise behind the meter and private wire options. It is important that the assessment framework for the Rule Change proposal includes modelling of the LGNC case compared to load defection scenarios i.e. the likely future case, and not simply compared to the status quo.

The framework should also address the corresponding issue of duplication of infrastructure and the resulting overall system costs, as the current NER may result in incentivising inefficient investment in such duplicate infrastructure. In the case of behind

[5] For simplicity, it is assumed that there is additional behind the meter generation INSTEAD of export from Site B.

the meter generation, many of these costs may be directly borne by consumers, rather than Network providers.

1.3 THE ASSESSMENT FRAMEWORK SHOULD USE A TIME FRAME CONSISTENT WITH ASSET LIFETIME

The assessment framework suggests a single regulatory period as the appropriate time frame for considering network cost impacts, and presumably also the impact on consumers. This is not a sufficient time frame, and may lead to inefficient investment outcomes and perpetuate the tendency for network augmentation to remain the preferred option for managing underlying load growth.

Firstly, this may occur because long-term reduction of load growth via embedded generation is not incentivised. Investment decisions for generation infrastructure are made with a life expectancy of 20 years plus, comparable to network infrastructure, and cannot necessarily respond in one or two year cycles. Restricting the assessment period to a five year cycle perpetuates a situation where non-network investment may not occur in time to avoid a constraint. The current framework for network support payments is aimed at regulatory cycles, and deferring immediate constraints. The LGNC is intended to reflect long term savings from reducing load growth across the network.

Secondly, the consultation paper suggests that discounting makes the value of reduced augmentation too low to consider outside of the regulatory period. We consider that the Long Run Marginal Cost should certainly include costs over a 10 – 20 year period, and that after discounting there is significant value remaining. For example, using a discount rate of 7%, 48% of value remains after 10 years, and 23% after 20 years.

Thirdly, the potential benefits of an LGNC include maintaining network utilisation over the long term. This includes refining the NER to take account of new technologies. Restricting the assessment framework to five years will not allow consideration of how rules will function with likely changes in embedded generation and storage.

Q1.2. WHAT IS THE RELEVANCE, IF ANY, OF RELIABILITY AND SECURITY FOR THE PURPOSES OF ASSESSING THE PROPOSED RULE (OR A MORE PREFERABLE RULE)?

If networks are correctly incentivised, distributed local generators can be encouraged to increase the reliability and security of networks. If managed correctly, local generation represents an alternate means of supply and has the potential to offer an additional level of redundancy to the energy delivery system.

By incentivising generation that has the ability to operate at the peak times advertised by the networks, the LGNC is one of the mechanisms for establishing a local generation fleet with greater ability to offer these redundancy benefits. However, further policies need to be implemented by DNSPs if the full redundancy benefits are to be realised. For example, implementing connection policies and guidelines that encourage EGs to provide a safe backup generation source, frequency support, voltage stabilisation and low voltage ride through at times of grid abnormalities.

It is vital that deterministic approaches to defining and rewarding reliability are not maintained in consideration of variable EG. The impact of variable EG on reducing peak demand can be retrospectively quantified, yet by traditional interpretations of availability no impact can be guaranteed for any single generator. Therefore intermittent EG needs to be dealt with in an aggregated, probabilistic fashion that reflects observed system impacts.

Q1.3 WHAT CHANGES, IF ANY, TO THE PROPOSED ASSESSMENT FRAMEWORK DO YOU CONSIDER APPROPRIATE?

4) The assessment framework should consider whether consumers should pay a reduced charge for partial use of the electricity network, and whether the Local Generation Network Credit is an effective way to deliver such reduced charges.

5) The assessment framework should consider the effectiveness of the LGNC to maintain utilisation of the distribution network, and the consequent effects on the long term costs for consumers. It is suggested that the framework includes modelling of the system costs per consumer with and without a LGNC.

6) The framework should use a timeframe of 15 – 20 years to assess the effects of an LGNC on network costs and on consumers.

7) The framework should consider the issue of duplication of network infrastructure and the costs that are borne by parties, other than Network providers, who may be incentivised under the current NER to inefficiently invest in such duplicate infrastructure. (See section 2 for discussion of this item)

2 PERCEIVED ISSUE WITH CURRENT NER

1. Are the current NER provisions (including changes that have been made but not yet come into effect) likely to provide appropriate price signals for efficient embedded generation? That is, do the NER provide incentives to individually or collectively (including through small generation aggregators) invest in and operate embedded generation assets in a way that will reduce total long-run costs of the electricity system?

The Institute welcomes a range of regulatory changes for embedded generation in recent years. Data and industry experience suggest, however, that the current NER provisions still do not provide incentives to invest in and operate embedded generation assets in a way that will reduce total long-run costs of the electricity system.

The current market structure disproportionately incentivises behind the meter generation, and while moves towards cost reflective pricing will go part of the way to addressing this issue, they will not incentivise export of local generation at times of high network demand, or deal with the perverse incentive to build private networks/lines. Further, cost reflective pricing in the absence of a local export price signal (a LGNC) may provide perverse incentives to invest in behind the meter infrastructure, and will increase the risk of customer disconnection in future years as the economics of battery storage and electric vehicles evolve. Customers will be unnecessarily forced into an ‘all or nothing’ decision regarding their use of the grid.

The small generator aggregator framework has the potential to provide some price signals for embedded generation, although very few business models have developed using this mechanism to date. However, the small generator aggregator framework is affected by the same issues as Network Support Payments and RIT-D/RIT-T, which are elaborated below.

2. Do the current NER provisions (including changes that have been made but not yet come into effect) appropriately incentivise network businesses to adopt both network and non-network solutions to achieve efficient investment in, and operation of, the electricity system that minimises long-term costs?

While available data is limited, the mismatch between cost-effective non-network opportunities that have been identified (22.6GW in 2011)[6] and those that have been deployed (350MW in 2010/11)[7] suggests that there is a substantial blockage in the deliberate utilisation of decentralised energy resources in the planning and operation of our electricity networks. While a number of regulatory changes outlines have been made since this time, we have not seen the step change required to deploy efficient levels of non-network opportunities. The solution is not simple, and requires overcoming technical,

[6] Dunstan *et al*. 2011. *Think Small: The Australian Decentralised Energy Roadmap: Issue 1, December 2011*. CSIRO Intelligent Grid Research Program. Institute for Sustainable Futures, University of Technology Sydney.

[7] Dunstan, C., Ghiotto, N., & Ross, K. 2011. Report of the 2011 Survey of Electricity Network Demand Management in Australia. Prepared for the Alliance to Save Energy by the Institute for Sustainable Futures, University of Technology Sydney.

information, regulatory, cultural and financial barriers. A LGNC mechanism in combination with policy mechanisms to address cultural bias towards business as usual options would help to complete the policy and regulatory environment for decentralised energy resources.

We also note that this question appears to focus solely on the incentives to network businesses and neglects that other parties invest, and in some cases are inefficiently incentivised to over-invest, in electricity supply and delivery mechanisms. Such over investments may take the form of private wires, micro grids or storage systems allowing for load defection and grid defection. The market needs to be structured to provide efficient investment price signals to these other parties as well.

2.1 COST REFLECTIVE NETWORK PRICING WILL NOT INCENTIVISE EFFICIENT EXPORTS FROM EG

The consultation paper suggests that *"Cost-reflective network tariffs can incentivise investment in forms of embedded generation that result in increased on-site consumption and/or export during peak times."*

The cost reflective pricing rule change will result in the value of generating a kWh behind the meter being lower, as network charges will be increased at peak events and away from volumetric charges. This has the potential to shift behind the meter generation (self-consumption) to times of greater value to the network. This signal may be particularly weak, however, as retailers are likely to bundle such charges so that small customers do not actually see them.

Relative to the current situation, cost reflective pricing will also de-incentivise behind the meter generation overall, as many network businesses appear to be shifting towards fixed charges. In some cases, this may correct an inefficient over investment in behind the meter generation. Vitally, cost reflective pricing will not provide a signal for *exported* generation, even where this has a positive impact on network peak events. This is illustrated in Box 1, which looks at a potential scenario for a generator under cost reflective pricing.

In summary, cost reflective pricing is not sufficient to incentivise efficient local generation investment or operation, and without a complementary LGNC, may provide perverse incentives. In particular, this includes over incentivising investment in generation or storage technologies to enable load and/or grid defection, without incentivising export at times when the network will benefit. This would be rectified by a value on exports through a LGNC. As such, a LGNC may be considered to be for exports what cost-reflective pricing is for consumption charges.

Box 1: Cost reflective pricing incentives: worked example

The DNSP sets the peak times as 4pm to 8pm and assesses that there is a 90% chance the system peak will occur during this window of 1460 hours in the year. All hours within this band have an equal chance of being the peak hour. As a result, the chance of any particular hour in this period being the system peak hour is 0.06%.

Customer A has 500kVA load at 4pm and a 400kVA cogeneration unit operating during business hours. The resulting peak charge levied on Customer A will be for 100kVA. By 6pm customer A's load is under 300kVA and as such their draw on the network is negligible as they can meet the load entirely from their own generation unit.

Customer B also has a 100kVA peak for the day, which occurs at 6pm. Customer B has no generation unit.

As a result, the two customers pay a total of 2 x 100kVA peak charges to the DNSP.

Customer A could choose to operate its generation unit at 6pm (the peak time). The network benefit would be the probabilistic value of a reduction of 100kVA for all network levels above the network level that connects the two customers. However, there is no incentive for Customer A to provide this generation at this time. Customer A's peak for the month has already been set based on the 4pm event.

The result of the cost reflective pricing rule change price signal is to de-incentivise EG exports even where that exported generation could assist in addressing peak caused by Customer B nearby.

The situation is worse than this however, and goes beyond Customer A simply not generating when they could provide useful network support. Customer A also has an incentive to invest in more technology to address her own 4pm peak. This could be through investing in increased generation, storage or load shifting capacity. This investment may occur even though addressing Customer A's own 4pm peak has exactly the same probabilistic impact on system peak as addressing Customer B's 6pm peak. The difference is that Customer B's peak can be addressed for little or no cost through utilising customer A's underused generator. The current market is set to incentivise over-investment in Customer A addressing their own peak instead of operating the generator to address Customer B's. This represents an inefficient over investment in energy supply and delivery infrastructure.

2.2 NETWORK SUPPORT PAYMENTS: COMPLEMENTARY TO AN LGNC

The NER allows for network support payments to be negotiated between generators and TNSPs (if >5MW) and DNSPs. The aggregator can perform this function on behalf of small generators, to better enable their participation in complex negotiations. These generally (but not exclusively) occur within the RIT-T or RIT-D mechanisms, which were created to ensure that alternatives to substantial network augmentations are considered at the point of investment, when a constraint is imminent. Network support payments are contractual arrangements with an individual party, with an individual administrative overhead, and are highly location specific.

Network support payments will not be available to most local generation, even when the generation provides network benefits, as RIT-T and RIT-D processes typically call for alternatives with a short time horizon (months rather than years), and very large amounts of capacity.

As a result, and when combined with the fact that the market for non-network alternatives is immature, very few of these processes actually result in delivery of non-network alternatives. This is due to several factors, including:

- these processes have been developed to align with lead times for centrally planned network projects
- these processes are only required for large projects,[8] with the aim of limiting administrative overheads for network businesses. Many of the best opportunities to defer long-term network expenditures are in fact smaller augmentation and refurbishment works.
- Contractual payments for network support are usually based on a guarantee of availability, defined in a traditional deterministic fashion,

These factors make the existing mechanisms fundamentally at odds with the way that embedded generation and other non-network alternatives enter the market. A large number of individual actors make decisions over time based on many factors, such as equipment replacement cycles, changes of property ownership, and the emergence of new products and business models.

Despite having the potential to reduce long-term network costs, smaller generation projects **are not driven exclusively by a network support opportunity**. Yet a network support opportunity may be the crucial factor to get many projects over the line, and could make more, smaller embedded generation projects cost-effective.

As such, even when opportunities to defer imminent augmentation exist, for smaller embedded generation the mechanism needs to be simpler, avoid administrative overheads such as individual negotiations, and credit EG with value at any point in time, not just when a constraint is imminent. This is a challenge for deterministic planning mindset, but aligns perfectly with the probabilistic approach to network planning that NEM jurisdictions are moving towards. This is where each marginal unit of load at risk is valued, not just when an augmentation is in the near term pipeline.

We recognise that the current network reflects a situation where non-network alternatives were inadequately deployed to overcome constraints, and that our regulatory environment has created a situation of network over capacity. It is therefore very likely that values will be created outside of a regulatory period, and there is uncertainty about how far in the future. The ISF project is addressing these issues with industry partners as part of its methodological approach.

[8] Transmission projects over $5m and distribution projects over $2m.

Thus while a LGNC is not intended to be highly location specific, LGNCs may be **supplemented** by network support payments where imminent infrastructure deferral values are much higher than average. EG is not credited twice, but can see a basic minimum credit through the LGNC, which may avoid areas becoming constrained in the first place[9], and a higher value if it applies to stimulate further opportunities within a particular region as required.

2.3 THE NER HAS NO MECHANISM TO ACKNOWLEDGE LOWER COSTS FOR PARTIAL NETWORK USE

The NER contains no mechanism to acknowledge lower service costs where only part of the network is used. Australian precedents for such mechanisms exists in the Western Australian Electricity Network Access Code, and in the form of 'prudential discounts' allowed in transmission pricing within the NER. These mechanisms were designed to ensure that inefficient duplication of infrastructure (private wires) did not occur.

The NER's pricing principles 6.18.5 (e) state that 'For each tariff class, the revenue expected to be recovered must lie on or between: (1) an upper bound representing the stand alone cost of serving the retail customers who belong to that class; and (2) a lower bound representing the avoidable cost of not serving those retail customers' (Australian Energy Market Commission, 2015).

The WA Electricity Network Access Code has a similar provision, but goes further to define provisions for providing reasonable pricing for the distribution network to be used to transfer electricity from one site to another, based on partial use of the network. This WA 'lowest avoided cost methodology' addresses the intent of the LGNC rule change insofar as providing reasonable charging for partial network use. However, it is cumbersome in its requirement for an identified 'point to point' recipient and creates a calculation complexity if many reference services are to be priced. As such it is more useful for larger generators with a specific identified purchasing customer base.

The LGNC methodology proposed addressed this implementation issue and contains mechanisms to offer economic benefits beyond merely avoiding duplication of infrastructure, through targeting payments at times where they can be of value in avoiding long-term development costs of the network.

[9] Where demand growth is met with increasing local generation in the absence of an LGNC, it could be that an area never nears its constraint, yet if the local generation is taken away, there could be insufficient capacity. Local generation which plays a role in avoiding constraints arising is not rewarded or incentivised under the NER. A LGNC addresses this equity issue.

Box 2❖ Western Australian example of a partial charge method for network services

Where a generator has identified a local customer (point to point) a methodology for assessing the use of the network is the lowest avoided cost of separately providing the service for that power flow as a stand-alone service. This method involves pricing a 'reference service' i.e., the cost of a new asset that meets the required function for transferring the energy. The total cost of this service is then divided by the expected volumetric throughput from the generator to that local customer. This amount is determined to be the value of network used by the transaction.

No new asset is constructed, however the existing assets of the Distributor are allowed to be used and a credit would be paid to the generator for any difference between the local customer's standard network fees and the network use value determined by the above method. This calculation methodology would ensure that private wire construction costs and the resultant inefficient duplication of networks by generators would be avoided. As distributors must offer the service at the cost of private wire/stand-alone service equivalent or lower.

This methodology appears to be allowed for within the Chapter 7 of the Western Australian Electricity Network Access Code^ (WAENAC) where: 7.3 (b) the reference tariff applying to a user: (i) at the lower bound, is equal to, or exceeds, the incremental cost of service provision; and (ii) at the upper bound, is equal to, or is less than, the stand-alone cost of service provision.

Chapter 7 also requires the distributor to provide discounts for distributed generation plant if this results in lower costs to the distributor as discounts for plant that reduces the service provider's capital and non-capital related cost as a result of the generator.

^Government of Western Australia. (2004). Electricity Networks Access Code. Retrieved from http://www.slp.wa.gov.au/gazette/gazette.nsf/lookup/2004-205/$file/gg205.pdf

❖Extract from Langham, E., Rutovitz, J., & McIntosh, L. (2015). *Towards a method to calculate a local network credit - Methodology Workshop Briefing Paper.*

2.4 SPECIFIC NOTES ON OTHER MECHANISMS

Avoided TUoS

There are two issues with avoided TUoS:

1. It only applies to generators over 5MW, and is so is not relevant to most small EG under consideration.
2. The 'locational' payment translates to a very low proportion of the total TUoS, even where an EG fully supplies a local customer and makes no use of the transmission system in any way.

We recommend that avoided TUoS be incorporated into the LGNC value, and generators receiving avoided TUoS as it is currently calculated be unable to receive both payments.

CESS and EBSS

These mechanisms have the potential to credit network businesses to ensure that they are not financially worse off if undertaking non-network alternatives. While relatively new, and potentially underutilized to date, they are welcomed additions to the regulatory landscape, but do not constitute mechanisms to deliver that value to non-network service providers. An LGNC is complementary to these mechanisms.

DMIS

The new DMIS is a vital addition to the regulatory framework. The details are not yet designed and will not come into effect until 2019, however will also focus on overcoming barriers to broad utilization of DM opportunities within the 5-year planning horizon. A more rapid introduction of this mechanism would support a regulatory environment alongside the LGNC.

DMIA

The DMIA is an important mechanism to allow network businesses to become comfortable with the use of non-network options to meet their license conditions. New options coming through the DMIA process could be eligible to join the portfolio of options that can access a LGNC.

SGAF

The Small Generation Aggregator (SGA) framework provides a welcome mechanism for small generators to band together to operate in the wholesale and ancillary services AEMO pools and also negotiate network support payments with DNSPs. The market is currently immature, with only companies such as Reposit Power willing to aggregate output from solar PV systems *with battery storage*, and Velocity Energy, targeting commercial embedded generation such as standby diesel and cogeneration. This allows small generators to participate in larger scale processes for procurement of non-network services. However, this process is limited to particular network areas with impending investments, as discussed above.

Distribution network planning and expansion framework

The transparency and reporting requirements in this rule change, focussed on the 5 year investment horizon, are welcomed. However, our work with all Network Service Providers in the NEM suggests that no non-network service providers have come forth to date with opportunities or enquiries based on the information provided in Annual Planning Reports. The Institute's Network Opportunity Mapping project seeks to rectify this issue and make the information fit for purpose for a distributed energy market, by making it easily digestible in map format with overlaid analysis. This information is complementary to network support payments, RIT-D, RIT-D processes, and the CESS and EBSS. It does not affect the need for an LGNC.

3 DETERMINING AVOIDED COSTS

[The current ISF project is developing a calculation methodology for an LGNC, and is currently trialling two alternative methods. For information on the methodology development see Langham, E. Rutovitz, J. & McIntosh, L., (2015) *Towards a method to calculate a local network credit.* A final recommended methodology will be available by June 2016.]

Q3.1 WHAT ARE THE FACTORS THAT INFLUENCE THE LONG-RUN NETWORK COSTS THAT CAN BE AVOIDED THROUGH EMBEDDED GENERATION?

The same factors applied when setting cost reflective tariffs aimed at signalling long run network costs are relevant to consider in the context of EG's contribution to addressing long-run network costs.

Unless one assumes there is zero underlying growth in electricity demand, all EG has the potential to influence **long-run** network costs in all network levels upstream of the connection point, through reducing augmentation capex, repex, and associated opex. A generator is capable of influencing **short-run** network costs when it is electrically located downstream of an imminent constraint and operates at times that the constraint is likely to be experienced.

In cases of zero or negative underlying growth in electricity demand, EG has the potential to influence **long-run** network costs through the downsizing of network capacity (and any associated opex) in network levels upstream of the connection point.

ISF's current LGNC calculation methodology matches the factors that DNSPs use when determining cost reflective usage tariffs. This is both because of the underlying intention of the LGNC, to a) provide a tariff for partial use of the network, and to b) ensure that the administrative costs of calculating and paying the tariff are minimised. The current proposed ISF methodology uses network region, customer class, and voltage level to categorise customers.

If the LGNC methodology calculates network benefit correctly, the LGNC payment should be equal to network savings in the long term, as it is based on the long run marginal costs (LRMC) of the network. However, in the same way that LRMC is a smeared cost across the network, the LGNC is a smeared payment. This means that in a constrained area, the LGNC may be less than the short-term network benefit, and in a non-constrained area, the LGNC may be greater than the short term network benefit.

It should be noted that the LRMC calculations of many network businesses actually are closer to the SRMC, as some businesses use only a short time horizon on 5 years. These are also artificially low at the moment due to a recent over investment in network capacity.

Location, voltage level & customer class

Geographical location is extremely important in assessing avoided short run costs, i.e. when there is an imminent constraint, as augmentation can only be avoided by EG in specific areas. This is relevant to network support payments, which are generally tied to a particular generator or demand response to address a specific constraint.

In the context of an LGNC, use of geographical location other than by matching a network provider's existing geographic zones, is unlikely to be practical as an input to calculating costs.

Most networks in the NEM consist of a single geographic zone, with the exception of the Ergon energy network that is split into East, West and Mt Isa zones. We note that networks do not currently provide locational demand signals due to the administrative overhead associated with calculating locational pricing. The LGNC should be constructed in the same manner in order to use the same inputs (long run marginal cost calculations), as it is very unlikely that providing a highly locational LGNC would be worth the administrative cost.

However, network businesses may adapt their tariff regimes to become increasingly geographically cost reflective and consequently more geographically targeted. As tariff setting practices change through setting LRMC in more targeted ways, the proposed ISF LGNC methodology is designed to automatically reflect any increased specificity.

Voltage level is one means of describing a generator's location in an electrical sense, and determines what network costs occur upstream of the generator. As only upstream costs are affected by EG, this is a crucial factor in calculating the potentially avoided costs.

Customer class is also a relevant factor, and to some extent has a locational element. Customers of a particular class are often located together, as the consumption behaviours within a customer class are similar, a customer class's peak usage times also likely to describe times that generation will be most valuable in an area containing members of that class.

Generator performance and not generator type

We propose that actual performance at peak times is more relevant than generator type in assessing a generator's influence on long run avoidable costs, and should determine payment.

Two generators, of different types, that generate the same amount at peak times as signalled by the network will have the same impact on long run avoided costs.

Nonetheless, a generator with less predictable performance in nominated peak times should not receive the same LGNC payment as one that is able to be consistent. The credit should be based on a generator's *actual* metered behaviour and not on its technology type. The proposed LGNC methodology allows for this and the initial results of the ISF trials show that generators whose performance varies will receive a significantly reduced credit, reflecting the fact that there is a lower probability that their generator has contributed to peak reduction. The results of these trials are expected to be published by early April.

As noted previously, it is important that deterministic approaches to defining and rewarding reliability are not maintained in consideration of variable EG. Intermittent EG should be considered in an aggregated, probabilistic fashion that reflects observed system impacts.

While generators of different types are likely to have different performance, to characterise a generator's expected performance by its type alone, and not on its actual historical generation will:

- Unfairly penalise some generators and reward others that have otherwise had the same beneficial effect on network peak events.
- Provide no incentive for dispatchable generators to operate in a manner which delivers network benefits.

Q3.2 CAN EMBEDDED GENERATION MATERIALLY REDUCE DNSPS' ONGOING OPERATING AND MAINTENANCE EXPENDITURE? IF SO, TO WHAT EXTENT DO THESE COST SAVINGS DEPEND ON THE LOCATION, VOLTAGE AND TYPE OF GENERATION?

EG can reduce long term network costs by:

- **Reducing the long term requirement for augmentation**: Unless one considers the underlying growth in electricity demand to be zero, then EG can reduce the need to augment.
- **Reducing replacement costs**: At some penetration, EG may reduce the long term demand on the network, as has already been seen with peak shifting as a result of PV installations. If effective signals are given, this should also facilitate network businesses to downsize components at the point of replacement.
- **Offering network services**: such as voltage and frequency regulation, although realising these benefits may require additional mechanisms to the LGNC).

As discussed in Section 1.3) the assessment framework should use a time period of 10 – 20 years, and not a single regulatory period.

4 SPECIFICITY OF CALCULATIONS

If LGNCs of some form were to be introduced:

Q4.1 What is the appropriate degree of specificity in the calculation of avoided network costs and, if relevant, operating and maintenance costs? For example, should different calculations be made for different voltage levels and/or geographic locations and, if so, what would be the criteria for distinguishing between levels/locations?

As covered in the AEMC's consultation paper and illustrated in box 5.1 in the consultation paper, there is a trade-off between how targeted the LGNC is, its effectiveness, and its administrative burden. We agree that this trade-off is important to consider.

The appropriate level of specificity in determining avoided network costs and setting an LGNC is that which is already used by networks in setting cost reflective network tariffs. As such the LGNC methodology in the Rule Change Proposal and developed in the ISF project uses the same LRMC values, broken down by customer class, geographic region and voltage level, as are used in establishing network's cost reflective pricing regime.

We note that the same arguments that apply in box 5.1 in the consultation paper[10] apply to the discussion regarding cost reflective tariffs. For example, if the DNSP undertakes a single LRMC calculation, the cost reflective tariff charged to customers in location A will be too low and the cost reflective tariff charged to customers in location B will be too high. As DNSPs already must engage with this trade-off in tariff setting it is clear that already there is a mechanism whereby decisions are made along the 'specificity' vs 'ease of implementation' spectrum and this is neither a problem that is insurmountable nor unique to the application of an LGNC.

In their paper 'Economic Concepts for Pricing Electricity Network Services'[11], NERA outline a set of economic principles to promote efficient tariff setting. This paper details 6 steps:

1. Analysing network expenditure
2. Analysing network growth,
3. Grouping customers into tariff classes,
4. Estimating LRMC for each tariff class,
5. Establishing a base tariff from the LRMC

[10] "The overall effect may be that the DNSP cannot defer or downsize the network investment in location A. That is, it would not achieve the savings that a bespoke LGNC would offer. However, embedded generators would still be paid LGNCs as if long-run network cost savings had been achieved."

[11] Kemp, A., Nunn, O., Chow, M., & Gainger, S. (2014). *Economic Concepts for Pricing Electricity Network Services A Report for the Australian Energy Market Commission*. Retrieved from http://www.aemc.gov.au/getattachment/f2475394-d9f6-497d-b5f0-8d59dabf5e1c/NERA-Economic-Consulting-—-Network-pricing-report.aspx

6. Marking up the base tariff as well as marking up the result to ensure total cost recovery.

The LGNC methodology in the Rule Change Proposal uses these same calculations when setting a benefit-reflective export credit, however there is no step 6 mark-up proposed.

When estimating LRMC, the cost reflective pricing regime gives a degree of freedom to networks in determining the methodology used, with the Average Incremental Cost (AIC) and the Perturbation method featuring as prominent options to be used by networks at their discretion.[12]

We also note that distributors in the NEM will typically already break down the network by voltage level in establishing the LRMC values. The criteria used to distinguish between voltage levels and locations for setting an LGNC should be no different to networks' existing criteria in establishing voltage levels and geographical locations.

By 'piggy-backing' on to DNSPs' existing calculation methodologies the LGNC proposed methodology results in minimal additional calculation burden on DNSPs while offering a level of specificity and accuracy commensurate with cost reflective tariffs.

Q 4.2 How often should this calculation be updated, recognising that the potential network cost savings can increase and decrease significantly over time as demand patterns change and network investments are made?

As per the discussion presented above, the LGNC value should be updated as often as other cost reflective tariffs are updated. This once again will match the existing result of the trade-off that DNSPs and regulators deem appropriate when weighing administrative burden of updating the calculation against long-term temporal specificity.

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[12] Box A1, page 118, AEMC. (2014). *Final Determination: Distribution Network Pricing Arrangements - Cost reflective pricing*. Retrieved from http://www.aemc.gov.au/Rule-Changes/Distribution-Network-Pricing-Arrangements

5 POTENTIAL BENEFITS OF THE PROPOSAL

We consider that the rule change proposal would provide benefits for all consumers, local generators, and networks businesses and would improve the ability of network businesses to cater to prosumers, who will become an increasing proportion of electricity consumers. In the long term, absolute network costs should be reduced. To the extent that an LGNC maintains utilisation of the distribution network (by reducing load defection and grid defection), the costs per consumer will be reduced even if absolute network costs remain the same or increase slightly.

The rule change proposal will also go some way towards correcting the current perverse incentives for consumers to invest in behind the meter solutions, even when those solutions are not the most economically efficient.

1. Compared with the current NER provisions, would the proposal:

(a) Provide superior or inferior price signals to embedded generators (including small-scale embedded generators) to incentivise them to invest in and operate those assets efficiently, thereby reducing long-term total system costs?

As discussed in previous sections, a Local Generation Network Credit would improve the price signals to embedded generation, and remove some of the perverse incentives for inefficient investment in generation, storage, or private wire infrastructure. See Box 1 in section 2 for a worked example.

At present there is little or no price signal to incentivise export from EG at the times when the network needs the generation. This would be addressed by a LGNC.

(b) Provide superior or inferior incentives to DNSPs to adopt efficient network and non-network solutions (including small-scale embedded generation) so as to reduce long-run total system costs?

The LGNC does not provide an incentive or disincentive to the DNSP to utilise non-network solutions for imminent constraints. However, the LGNC encourages EG to export at peak times, with the effect of reducing long term load growth, allowing for reduced long term augmentation and / or reduced replacement costs. As an LGNC systematically rewards EG to reflect long term cost savings, and incentivises export at times when it is useful to the network, it can be expected to avoid areas becoming constrained in the long term.

(c) Have any potential beneficial or detrimental effects on any non-price attributes of the service, such as network reliability and/or security of supply?

The proposal is unlikely to impact on reliability and/ or security of supply. To the extent that the proposal increases the deployment of EG, there are likely to be positive outcomes for managing reliability at least cost through the diversification of supply sources, providing NSPs are effectively able to integrate probabilistic risk management into their planning processes.

(d) Reduce or increase the prices consumers pay for electricity?

Overall an LGNC should reduce the prices that consumers pay for electricity compared to what they would otherwise pay. There are two aspects to this reduction:

- A saving in augmentation, operational and replacement costs in the long term, as EG will reduce underlying demand. These savings are unlikely to be seen strongly in the first regulatory period, as much of the network has excess capacity, so there may be a small increase in absolute network costs in the short term.

- To the extent that an LGNC maintains utilisation in the network, it will reduce consumer costs. If load goes behind meter, whether by additional generation or storage equipment or by a private wire, the network cost savings are equivalent or less than would be achieved by the same reduction in grid transported load as a result of export[13]. However, if the generation is encouraged in the network at peak times, and a credit is paid, the total reduction in payment for network services is considerably lower than if that load is taken behind the meter and no credit is paid. (see Figure 3) In effect, maintaining utilisation means that the remaining network costs are shared between more users. This is explored in some detail in section 1.2.

2. To what extent do your answers to 1(a) to (d) depend on:

(a) To whom LGNCs are applied (e.g. whether it is applied to all embedded generators or whether there are criteria based on a generator's capacity, availability and/or location)?

(b) The degree of specificity in the calculation of avoided network costs (i.e. whether separate calculations are made for different voltage levels and/or locations) and how often it is updated?

Our answers are based on an LGNC using the methodology developed during the ISF project, or something similar. In this methodology the LGNC will be paid according to the voltage level, network area, customer class, and will be performance based according to when the generator operates.

While network businesses could update such tariffs in the annual tariff setting process, long run costs and other factors such as critical peak times should not change much each year, and as such it is anticipated that LGNC values would not necessarily need to be updated with such frequency.

(c) The proportion of the estimated avoided network costs that are reflected in the LGNCs paid to embedded generators?

We have assumed that all the calculated network savings are passed on to the generator, enabling more choice and competition in energy supply. It is possible that an efficiency dividend could be reserved to allow a direct benefit to non-generating consumers. However, ISF's LGNC value calculation does not include the broader benefit associated

[13] Network costs savings will be less to the extent that the structure of the LGNC incentivizes peak export in particular.

with reducing load or grid defection. We propose that this component should constitute the direct benefit flowing to non-participating customers in the long term.

3. If you do not consider that the proposed rule would enhance the NEO, are there potential alternative approaches that may do so?

We consider the proposed rule to be an improvement to the NER, and would go some way to making the NER more suitable to an electricity system with a much greater penetration of distributed electricity systems.

At present the LGNC seems the most viable option to achieve the outcomes stated in the LGNC Rule Change proposal.

6 POTENTIAL COSTS OF DESIGN, IMPLEMENTATION AND ADMINISTRATION

Q6.1. What changes would DNSPs and other parties need to make to their existing systems and processes to enable the design, implementation and administration of LGNCs?

ISF has identified the following changes that would need to be implemented:

- DNSPs would be required to create additional line items within their existing system of tariff classes.
- DNSPs would need to assess the value of the LGNC. This has been done within the trials with a spreadsheet model, which would require updating with new input data each regulatory period. ISF has developed a prototype of this spreadsheet and found that DNSPs have little difficulty in obtaining the relevant data to populate the inputs.
- DNSPs and retailers would need to update their tariff proposals and public facing tariff explanation documents to include information on the LGNC.
- Electricity retailers would need to include the additional tariff class in their billing systems. It is likely that this would a trivial addition compared to the suite of new tariffs that are being created under the switch to cost reflective pricing, and could be achieved at the same time.

As discussed in answers in the previous sections, the proposed LGNC calculation and implementation methodology has been designed to mirror the existing DNSP tariff setting process as much as possible. This has the effect of minimising the cost of implementation.

Networks such as Ausnet[14] and ActewAGL[15] already pay a credit to some generators; this credit takes a very similar form to an LGNC. (Ausnet, 2015), (ActewAGL, 2015). Other networks also have systems for administering and (via retailers) paying feed-in tariffs to generators. While the LGNC is considerably different to a feed-in tariff, in that it relates to network value and not energy value, the mechanisms for administering it are quite similar.

a) We have not received feedback from DNSPs that the costs of implementation are likely to differ depending on to whom LGNCs are applied.
b) To the extent that the degree of specificity, particularly locational specificity, is different from existing tariff setting calculations, there would be increases in DNSP

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[14] Ausnet. (2015). *Ausnet Annual Tariff Proposal 2015 (Vol. 14).* Retrieved from https://www.aer.gov.au/sites/default/files/Annual Tariff Report 2015 Approved_0.pdf

[15] ActewAGL. (2015). *ActewAGL Electricity Network Prices 2015 - 16.* Retrieved from http://www.actewagl.com.au/~/media/ActewAGL/ActewAGL-Files/About-us/Electricity-network/Electricity-network-prices/Electricity-network-prices-2014-15.ashx?la=en

costs. As a consequence, ISF considers that this cost should be minimised through matching the specificity of cost reflective tariffs.

c) As the proposed LGNC calculation is dependent on the LRMC values used by networks in determining cost reflective prices, the calculation should be updated as often as cost reflective tariffs are updated.

d) LGNCs should be paid on the customer's existing billing cycle.

Q6.2 What are the likely costs associated with undertaking the changes described above and how are these likely to vary depending on the factors set out in 1(a) to (d)?

In general, the costs that DNSPs will face will be larger if there are significant differences in calculation from standard DNSP tariff setting and will be smaller if the calculation and administration matches existing DNSP practices.

Q6.3 How do these costs compare to the expected benefits of the proposed rule change?

As the costs identified are minimal, they are small in comparison to the expected long-term benefits of the proposed rule change.

7 POTENTIAL MISINTERPRETATIONS IN THE CONSULTATION PAPER

This section covers notes issues in the consultation paper which are not covered in the sections above, and appear to be misinterpretations of the LGNC rule change proposal.

Creation of a separate payment mechanism (Section 3.3 and Summary)

The Consultation Paper states: *"LGNCs would be a separate negative network tariff, and would create a new payment relationship between DNSPs and embedded generators."*

The LGNC would not create a new payment relationship, but would mirror existing payment relationships. It is assumed that the retailer would pass through the LGNC payment to generators in the same manner that the retailer also passes through network charges to both generators and consumers.

Size of generator that may benefit from an LGNC (Sections 2.1.1, 3.3, and 5.1.1)

The Consultation Paper suggests that the LGNC may apply to large generators, and mentions "large wind farms" several times, and suggests that all sizes of generators should be considered. This is not appropriate, as only generators that connect to the distribution system can benefit from an LGNC. Large wind farms, for example, are not connected to the distribution network,[16] and therefore would not be eligible for the LGNC.

In effect an upper limit to the generator size is set simply because an embedded generator is by definition connected to the distribution network, which has limits on the connection capacity. It is highly unlikely that connection of generators much larger than 50 MW would be acceptable, and in most cases embedded generation will be considerably smaller.

Availability and variability (Sections 2.1.1, 3.3, and summary)

The Consultation Paper suggests the rule change proposal advocates for all generators to be paid the same regardless of availability. We consider this a misinterpretation of the "technology neutral" requirement. The proponents are suggesting a performance-based payment, which is available to all types of generator based on when they are in fact available, rather than a notional adjustment for potential availability.

Likewise, there is a suggestion that variability means that it is difficult for intermittent sources to provide network benefits. For example, in Section 2.1.1:

"— their output can be quite variable – for example, the production of solar generation is dependent on cloud cover; and

— their output can be difficult to predict – because they are influenced by the elements, there is no guarantee that a particular solar or wind generator will be available at any particular time."

This statement is out of date. Forecasting means that predictability is quite good, particularly for aggregated generators. The forecasting required is not dissimilar to the

[16] A very small wind farm, such as the 4 MW community wind farm Hepburn Wind, may be connected to the distribution network but certainly does not qualify as large. For comparison, the fourteen wind farms under construction or commissioned during 2014 averaged 130 MW each.

forecasting that network businesses already do when aggregating individual customer loads into a network demand profile. Individual consumers also display the two elements of 'intermittency' described in section 2.1.1 in the AEMC's consultation paper. When aggregated however, many individual loads combined with diversity factors and an understanding of seasonal weather patterns allow network businesses to make sufficient forecasts to set critical peak, peak, shoulder and off peak tariff times. The level of forecasting required for setting similar critical peak, peak, shoulder, and off peak times for generation is no more complex.

An additional consideration is that contractual payments for network support are usually based on a guarantee of availability, defined in a traditional deterministic fashion. Network businesses are reluctant to negotiate network support payments unless a generator has a willingness to absolutely guarantee availability. This contrasts with the treatment of an equivalent customer's reductions in demand, which is automatically rewarded through lower network charges, even though the customer has made no such demand reduction guarantee to the network.

As discussed in section 3 above, a marginal generator's export impact is exactly the same as marginal customer's reduced demand impact and should be acknowledged as such.

Cost increases as a result of embedded generation (Section 2.1.2)

The background information presented suggests there may be additional system costs that arise because of an increase in the amount of embedded generation. In the cases below we believe it to be erroneous to suggest that the introduction of an LGNC will increase costs.

1) *.. additional spending on distribution infrastructure that is required to enable a greater amount of embedded generation to be exported throughout the local network whilst meeting the applicable reliability standards"* (Section 2.1.2)

At present, these costs are met by the embedded generator upon connection. In the longer term a discussion is needed on how these costs should be met – that is, industry discussion on whether we have a fit for purpose network given the likely growth in embedded generation is warranted.

2) *"network businesses incurring transaction costs interacting with embedded generators, such as costs associated with negotiating connection agreements and network support payments" (Section 2.1.2)*

These costs are either inapplicable to an LGNC payment, or are already covered by the applicant generator. Connection agreement costs are already covered in network businesses connection application fees, which are met by the applicant generator. The NER already allows for reasonable cost recovery of these costs. Costs associated with network support payments are not relevant to an LGNC, as an LGNC is a tariff. Network support payments do require contractual arrangements, which are **only** negotiated where there is a direct and immediate saving. Any contractual overheads associated with negotiating network support payments are taken account of in amount that a non-network service provider can be paid for the support provided.

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