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

# RULE CHANGE PROPOSAL SUBMITTED BY:

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# DISCLAIMER

This submission has been prepared for the City of Sydney, the Total Environment Centre ("TEC") and the Property Council of Australia for their Rule change request related to the requirement for distribution businesses to offer a Local Generation Network Credit (LGNC).

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# Executive summary

The proponents of this Rule change are the City of Sydney, the Total Environment Centre (TEC) and the Property Council of Australia.

The proponents are requesting this Rule change because the electricity supply chain is undergoing significant long-term change.

Electricity supply is becoming increasingly decentralised. This is a fundamental change from the centralised electricity supply chain in which electrical energy flowed in one direction from very large centralised power stations over long distances via high voltage transmission and sub-transmission lines to reach end users connected to local distribution networks.

An increasing proportion of end users now generate some of their own electricity, and an increasing proportion of electricity flows bi-directionally, especially within local distribution elements.

It is acknowledged that the National Electricity Rules ("the Rules") do provide some incentives for efficient investment in smaller scale generation that is connected to the electricity supply chain via distribution networks (this is referred to in the submission as "local generation").

These incentives include:

- the recent Rule change that increases cost-reflectivity in distribution network pricing, which encourages efficient investment in local generation that displaces on-site usage;
- incentives for distribution businesses to negotiate with local generators for the provision of "Network Support Payments" ('NSP') where this represents the least cost means of balancing supply and demand for standard control services;
- requirements for distribution businesses to make payments to local generators if their operation allows a distribution business to reduce its Locational Transmission Use of Service payments ('Avoided TUoS payments'); and
- the Regulatory Investment Test – Distribution (RIT-D) arrangements that require distribution businesses to undertake a systematic assessment of the market for non-network solutions to alleviate capacity constraints that would otherwise lead to augmentation expenditure above a certain dollar ($5 million) threshold.

However, the incentives for local generation in the current Rules either do not provide adequate recognition of the benefits that local generation can provide, and/or may not be readily accessible to small-scale local generators:

- The recent Rule change for distribution network pricing only addresses the cost-reflectivity of network pricing signals concerning electricity consumption. It does not explicitly address the situation where an end customer exports energy to the grid. Efficient price signals for consumption will not in and of themselves lead to the efficient sizing, location and operation of local generation that can be used to export of energy to the grid at times of congestion.
- The 'NSP', 'Avoided TUoS' and the 'RIT-D' arrangements are unlikely to be accessible to many small-scale local generators who export energy into the grid. The high transaction and administrative costs of the bespoke arrangements generally required in the 'NSP', 'Avoided TUoS' and RIT-D will often exceed the benefits these arrangements could provide to small-scale local generators. In addition, the NSP and RIT-D arrangements generally require the local generator to provide firm capacity, which is likely to be difficult for 'individual' small-scale generators to commit to.

To address these gaps in the current Rules with regard to local generation this paper proposes that a Rule change be made that requires distribution businesses to implement a local generation network credit (LGNC).

The key features of the proposed Rule change are as follows:

- The LGNC is a price signal for exported energy.
- It reflects the long-term economic benefits (in the form of capacity support and avoided energy transportation costs) that the export of energy from a local generator provides to a distribution business, including reduced or avoided transmission costs that would otherwise be passed through to end users.
- The LGNC would be signalled to customers in the form of a posted credit that would be able to be adjusted yearly as part of the DNSP's broader Annual Pricing Submission process.
- The detail of the credit would be developed by individual distribution businesses, based on guidelines to be prepared by the Australian Energy Regulator. The credit could vary by voltage level (and potentially by location) where the allocative efficiency benefits of that greater level of disaggregation exceed the administrative costs of developing and administering it.
- The credit would be available to local generators of any size (not just to larger local generators) as:
  - This overcomes the gap in the Rules whereby small-scale local generators are unable to monetise the benefits that they collectively provide to the grid, and
  - By not limiting size, the credit can assist in enabling localised groups of embedded generators of sufficient aggregate size and scale to be treated as a diversified portfolio, as opposed to being treated as individual generators (which in turn overcomes the need for an individual generator to provide a 'firm' guarantee of capacity support).
- The LGNC would be optional for local generators i.e. they would be able to choose whether or not to receive it. This means that local generators would be able to choose whether to bear the cost of any metering changes that might be required in order for the exported energy to be adequately measured in order for the credit to be paid.
- The credit would not be allowed to revert to a charge in situations where the cost of catering for bi-directional flows is deemed to exceed the benefits of the exported electricity to the network. This is based on our assumption that distribution businesses will use other means for managing this issue, should it arise. These include (a) disallowing any further connections in an area where this situation arises, or (b) smearing any such additional costs across all applicable tariff classes.

The proponents consider that the LGNC is consistent with the Rules and the National Electricity Objective in that:

- It advances cost-reflectivity in network pricing by providing a price signal for exported energy where and to the extent that the exported energy serves to defer or avoid augmentation, reduce the cost of replacement assets, or reduce load at risk.
- In so doing, it addresses a gap in the Rules whereby most local generators who export energy to the grid are unable to monetise the benefits that they collectively provide to the grid.

- It will exert downward pressure on prices and provide benefits to consumers over the long term, because it incentivises investment in alternatives with lower costs than the long run marginal cost (LRMC) of the network.
- By creating a portfolio with an expectable impact on peak demand, it can justify treating certain non-dispatchable generation sources as resources that can be integrated into network planning.
- More generally, it creates a platform through which local generation/injection becomes a resource that must be acknowledged and integrated into network planning, thereby providing a tool that will assist in the transition to the operations and regulatory framework required in an increasingly bi-directional electricity system.

Finally, the proponents note that:

- The potential for local generation to reduce peak demand has already been recognised in material published by several distribution businesses and the Australian Energy Market Organisation (AEMO), and
- There is precedent for such an approach.
    - The UK Office of Gas and Electricity Markets (Ofgem) requires each distribution network to publish as part of its annual schedule of distribution tariffs a credit tariff that is payable to 'decentralised generators'. The decentralised generator tariffs are calculated annually based on a standard methodology provided by Ofgem, and vary for different classes of generator depending on the size of the generator, the level of intermittency and time of operation[1].
    - Within Australia, AusNet Services offer similar credit arrangements[2].

The proposed Rule change would make the offering of such credits a requirement. As noted above, it is anticipated that the AER would publish a Guideline to support the development of the LGNC, to be updated from time to time.

1 http://www.energynetworks.org/electricity/regulation/duos-charges/common-distribution-charging-methodology.html

2 See, for example, tariffs SUN2B and NEE23 in AusNet Services, *Electricity Distribution Annual Tariff Proposal 2015*, 1 January 2015, pp 81 and 82..

# 1. Background

The electricity supply chain is undergoing fundamental change. What until quite recently was a system in which electricity flowed in one direction from large, centralised power stations to end users through a network of high- and low-voltage (HV and LV) poles and wires is increasingly becoming a system in which consumers are also producers, and electricity is flowing bi-directionally. Between 1 January 2001 and 31 December 2014, a total of 3,994 MW of photovoltaic generation capacity was installed (or was pending installation) in small-scale applications across Australia[3].

Recent announcements from a number of manufacturers and suppliers that they will make residential-sized battery packs commercially available in the very near future, and continuing interest in electric vehicles, only serve to increase the likelihood that bi-directional flows will increase.

These technologies also represent an alternative to exporting excess energy back into the grid (i.e., a customer can install a battery instead of exporting energy back into the grid). Given this technological possibility, it is important that economically efficient price signals exist for energy exported to the grid. Where exported energy is not valued (priced) correctly, inefficient investment in these alternative technologies may ensue.

Similarly, over a number of years, there has been investment in a wide variety of cogeneration and trigeneration projects at various scales that involve (or have the potential to involve) export of electricity to distribution networks.

There has also been increased interest in ensuring that electricity price signals – and especially network pricing – is as cost-reflective as possible, in order to increase allocative efficiency and help drive the most economic benefit possible from investments in electricity infrastructure. Reducing cost and increasing interest in alternative, local electricity generation make the availability of cost-reflective price signals even more important for ensuring efficient investment in the electricity supply chain, especially in regards to local generation and other decentralised means of injecting electricity into the grid, such as batteries.

The transition to a more decentralised electricity system must take into account the interest of all affected parties. For local generators, this means financial recognition of the benefits that their exported energy may provide in managing electricity supply, because this encourages orderly participation. For networks, orderly participation is important because this means networks can plan for local generation in managing current demand and in developing future forecasts.

A number of barriers and gaps in the Rules have confronted customers that have sought to install local generation that exports energy to the grid. The gap that this Rule change proposal seeks to address is the fact that network tariffs do not and are not required to compensate local generation for the future benefits that their export of energy to the grid may provide to other electricity consumers[4].

This gap has affected cogeneration and trigeneration applications in commercial buildings and industrial facilities, and the use of diesel and biomass generation in industrial and agricultural facilities.

3 http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/postcode-data-for-small-scale-installations.

4 This is in contrast to the government-initiated feed-in tariffs which initially over-compensated users of rooftop PV systems for the reduction in energy consumption and energy export they have provided.

It also affects PV systems and will affect the deployment of batteries either as standalone devices or in combination with other technologies like rooftop PV and electric vehicles. As an example, the lack of a cost-reflective price for the value of local generation exporting energy to the grid at times of network peak demand is likely to lead to either over-investment in customer-side battery storage, and/or sub-optimal battery charge/discharge strategies.

In response, a significant amount of work has already been undertaken to identify the best means for addressing and overcoming these barriers.

In early 2014, the City of Sydney and TEC commissioned the Institute for Sustainable Futures at the University of Technology Sydney (ISF) to prepare a report on options for calculating the benefits of local electricity generation and consumption. ISF investigated different options for network payments to reward local generation and/or local consumption of electricity. The options included:

- a credit payable to local generators based on the fact that they make more limited use of network infrastructure and contribute to mitigating peak demand events. This was termed a local generation network credit (LGNC), and
- a reduced set of charges (for local generators and/or for local electricity customers) in situations where a formal link is established (most likely, via netting off on a time of use basis) between an individual local generator and an individual local electricity customer. This was termed virtual net metering (VPN) or virtual private wire.

In mid-2014, the City of Sydney commissioned ISF to prepare an issues paper setting out key issues in relation to local generation. The issues paper built on the work that had already done for the network benefits report.

A primary purpose of the issues paper was to serve as the basis for engagement with key stakeholders (both network service providers and local generation proponents). This engagement established the overall receptivity of stakeholders to the options that had been identified and expressed interest in more detailed economic modelling and the possible development of a Rule change proposal to mandate the use of network benefit payments to local generators.

At the same time:

- TEC commissioned independent advice on regulatory considerations in regard to a range of proposals (principally, LGNC and VPN), and
- preliminary legal advice was obtained on the prospects and form of the necessary change to the National Electricity Rules to better reward local generation in a manner consistent with the National Electricity Objective (NEO).

The findings of the issue paper, stakeholder feedback, independent advice on regulatory considerations regarding the LGNC and the VPN, and the preliminary legal advice have all served as input to this Rule change proposal.

# 2. Purpose and contents

This paper proposes a change in the National Electricity Rules (NER) to require electricity distribution businesses to establish posted tariffs that reflect the economic benefits that local electricity generation delivers to or imposes on the distribution system.

Consistent with the Guidelines[5] issued by the Australian Energy Market Commission (AEMC), this document provides:

- a description of the proposed Rule – see Section 3;
- a statement of the nature and scope of the issues concerning the existing Rules and an explanation of how the proposed Rule will address these issues – see Section 4;
- an explanation of how the proposed Rule would or would be likely to contribute to the achievement of the National Electricity Objective – see Section 5;
- the rationale for the credit being paid to the local generator – see Section 6; and
- an explanation of the expected benefits and costs of the proposed Rule change and the potential impacts of the change on those likely to be affected – see Section 7.

The AEMC's Guidelines also request that "draft wording for the proposed Rule" be provided.

Appendix A of this submission provides such drafting in terms of specific proposed changes to various sections of the Rules.

5 Australian Energy Market Commission, *Guidelines for proponents: Preparing a Rule change request - National Electricity Rules*, December 2013.

# 3. A description of the proposed Rule change

## 3.1. Overview of proposed Rule

### 3.1.1. Basic features

The proponents are proposing that a Rule change be made to require distribution businesses to implement a local generation network credit (LGNC) to reflect the benefits associated with electricity generation that is embedded within distribution networks (in this submission, called "local generation").

In practical terms, this would require distribution businesses to:

- develop a credit (negative tariff)[6] that reflects the economic benefits that local electricity generation delivers to or imposes on the distribution system, and
- signal this to customers of the distribution business in the form of a posted tariff that would be able to be adjusted yearly as part of the broader Annual Pricing Submission process.

More specifically, the proposed Rule change prescribes that:

- the credit be based on a measure of the **long-term** benefits (in the form of capacity support, and avoided energy transportation costs) that the export of energy from an embedded generator provides to customers of distribution businesses. This includes the benefit of being able to avoid transmission (economic) costs, as measured by the locational component of the transmission charge[7]. The use of a 'long-term' assessment of benefits is appropriate because it reflects the need for network businesses and local generators to make long-term investment decisions. It also better enables a transition to a new, bi-directional environment, which could be consistent with the dynamic component of economic efficiency and therefore promotes the long-term interests of consumers. Finally, it is consistent with the recent Rule change regarding the requirement to base cost-reflective network charges on long-run marginal costs (LRMC)
- distribution businesses be required to demonstrate that they have given explicit consideration to disaggregating the LGNC by voltage level (and potentially spatially) where the allocative efficiency benefits of providing different price signals at different voltage levels (and potentially in different areas) exceed the administrative costs of doing so; and
- the AER should be required to prepare a set of Guidelines (within a stated time from the promulgation of the Rule change) that provides more details to distribution businesses as to how they must go about developing an LGNC in accordance with the Rules. The benefits of such Guidelines being in place is that they are likely to:
  - reduce the implementation costs incurred by distribution businesses, as the Guidelines should limit the likelihood of a distribution business' initial credit payments being deemed by the AER as being inconsistent with the promulgated Rule, and
  - promote more consistent and comprehensive approaches being adopted by distribution businesses to the development of the LGNC, thus limiting the administrative costs to embedded generators (and other interested stakeholders) in having to understand and respond to the varying forms of credits proposed by different network businesses, relative to if no Guidelines were implemented.

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6 Henceforth, the term credit will be used to cover the tariff.

7 The credit should also include any other avoided transmission costs, including, for example, avoided connection costs.

### 3.1.2. Structure of the proposed LGNC

As noted, the specific structure and level of the LGNC will be finalised by individual distribution businesses with reference to the AER Guidelines and overarching Rules[8]. However, it would be expected that the credit would comprise at least two parts[9]:

- a credit (negative tariff) based on an estimate of the long-run avoided cost stemming from not having to augment the local grid as a result of electricity exported to the grid during periods of network system (or local area) peak demand. It is expected that this credit would be based on:
  - the **long-run** avoided capacity and operational costs (analogous to the LRMC) in *upstream parts of network*[10] resulting from the collective operation of small-scale local generators connected to the distribution network, *less*
  - any reasonable increase in capital and operating costs stemming from having to cater for **bi-directional/localised energy generation** in system peak demand periods, instead of utilising centralised energy generation.
- a credit (tariff) based on the operating and maintenance costs that the network business would avoid (incur) as a result of electricity being exported by the embedded generator to the grid at other (non-peak) times. It is expected that this credit would be based on:
  - the avoided operational costs in upstream parts of network (e.g., the high voltage (HV) and sub-transmission (ST) network, assuming the generator is connected to the low voltage (LV) network), *less*
  - any reasonable increase in capital and operating costs stemming from having to cater for **bi-directional/localised energy generation in non-peak periods,** instead of utilising centralised energy generation.

The components of the LGNC described above should also capture avoided transmission use-of-system charges[11].

The credit could potentially also include a capacity payment based on the availability of the local generator at particular times (typically, through the peak period).

The LGNC could be further disaggregated where the allocative efficiency benefits of such disaggregated price signals exceeds the costs of developing and administering them:

- most likely by voltage level, to reflect the fact that the benefits to a distribution business will vary, depending on how far up its system (i.e., at which voltage level) the local generator is connected; and

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8 This is because the structure and level of any tariff will be a function of the particular characteristics of the distribution business, and therefore, it almost inevitably will differ from business to business. In these circumstances, it is not appropriate to codify in the Rules the exact form and structure of the tariff.

9 The credit could potentially also include a capacity payment based on the availability of the local generator at particular times (typically, through the peak period).

10 This means that the benefit of a local generator connected to the LV part of the network would be the avoided costs in the HV and ST parts of the network. This in turn would mean that the time of day/week/month/year underpinning the payment would not be related to when the LV part of the network peaks, but rather when the HV and ST parts of the network peak.

11 This assumes that transmission use-of-system charges are cost reflective. If that is not the case, alternative approaches may need to be considered.

- potentially also by area, to reflect:
  - the long-run avoided capacity and operational costs of the distribution business in a particular area (noting that the augmentation capital expenditure of a distribution business will be driven by the specific locations in which capacity augmentation is required, not by the increase in overall system-wide peak demand), and
  - the amount and generation profile of the local generation in a particular area, and the costs this causes in relation to catering for bi-directional flows in that area. To qualify for the credit, the output of the local generator would have to be metered such that the amount of electricity exported to the grid could be measured by the half hour.

### 3.1.3. Who would be eligible for the LGNC

The LGNC should:

- Be available to local generators of any size (not just to the larger generators that are embedded in distribution networks), as this increases the pool of local generators eligible to access the LGNC, over and above those that would be of a sufficient size and scale to access existing schemes such as the Network Support Payments. Increasing the pool of eligible generators also allows these generators to be treated as a diversified portfolio, as opposed to being treated as individual generators providing network support in specific locations. This negates the need to have a specific contractual relationship (i.e., a guarantee of firmness) with each generator regarding how much network support they will provide at certain times of the day/week/month/year (e.g. contracts for network support payment).
- Be optional for local generators; that is, they would be able to choose whether or not to receive a LGNC and in doing so be able to choose whether or not to bear the cost of any metering changes that may be required to facilitate payment of the LGNC. This ensures that the upfront cost of implementation will be minimised, and moreover, if cost-reflective credit payments are signalled to generators, generators will only elect to take up the credit payment where those benefits (which is the credit payment, and which also reflects the benefit to the network business if set at cost-reflective levels) exceed the costs to the generator of obtaining that credit payment, and
- Not exclude generators that are also eligible to receive network support payments (and payments made under the RIT-D) at times when the relevant network area is approaching the need for augmentation[12]. However, any such payment under those schemes would need to take into consideration any payments that may already be being made to local generators via the LGNC (e.g., in such cases, any network support payments and RIT-D payments would accrue at the difference between the short range and long range marginal cost of supply).

## 3.2. Amendments and additions needed to Chapter 6 to implement the proposed Rule change

The following amendments and additions to the existing Rules have been identified as being needed to implement the intent of the Rule change being proposed:

12 In areas where new development requires an extension to the grid local generation can provide a benefit to all users of that grid by reducing the amount of infrastructure required. However, that situation is better addressed through a cost-reflective connection charge.

- An amendment to clause 6.2.8 (a) (1) to require that the AER make and publish Guidelines regarding the Local Generation Network Credit
- An amendment to clause 6.8.2 (c1) to replace the term *electricity consumers* with the term *network service users* to allow it to apply to persons that either consume electricity from or export electricity to the network or that do both.
- An amendment to clause 6.8.2 (c1a) to replace the term *retail customers* with the term *network service users* to allow it to apply to persons that either consume electricity from or export electricity to the network, or that do both. Note that this change is also proposed for the same reason in a number of other clauses, specifically:
  - 6.18.1A (a) (1)
  - 6.18.1A (a) (2)
  - 6.18.3 (c)
  - 6.18.3 (d) (1)
  - the title and all clauses of clause 6.18.4
  - throughout clause 6.18.5 except for as it is proposed below in clause 6.18.5 (e)
  - 6.19.2
- The addition of a new clause 6.18.1A (a) (1a) to make explicit the fact that the tariff classes discussed in clause 6.18.1A (a) (1) can include one or more tariff classes of negative tariffs that provide a credit for electricity exported to the distribution system by local generators or by retail customers with embedded generating units.
- The amendment of clause 6.18.4 (b) to add the word 'exports' as a basis of charge that can be referenced in a *charging parameter* applicable to a *network service user*.
- The amendment of clause 6.18.5 (a) to add the phrase 'to provide credits' after the word 'charges' to make it clear that this clause applies to the local generation network credit tariff that is the subject of this Rule change proposal.
- The amendment of clause 6.18.5 (a) to make it clear that the local generation network credit tariff that is the subject of this Rule change proposal should reflect the degree to which the export of electricity from *embedded generating units* of the *network service user* reduce the long-run marginal costs of providing *direct control services*.
- The amendment of clause 6.18.5 (e) to add the words 'for *retail customers*' to make it clear that this clause applies to tariffs applicable to retail customers, but does not apply to other types of network service users.
- The addition of clause 6.18.5 (f1) to make it clear that any tariff that applies to *network service users* who are *local generators* or *retail customers* with *embedded generating units* must include credits for:
  - electricity delivered to the network during network peak demand periods that are based on the avoided capacity and operational costs in those components of the *distribution and transmission systems* upstream of the *embedded generating unit* less any increase in capital and operating costs stemming from having to cater for exports from *embedded generating units*, instead of utilising upstream energy generation; and

  - electricity delivered to the network during outside of network peak demand periods that are based on the avoided operational costs in those components of the *distribution and transmission systems* upstream of the *embedded generating unit* less any increase in capital and operating costs stemming from having to cater for exports from *embedded generating units*, instead of utilising upstream energy generation; but that
  - these tariffs cannot include a positive charge to *network service users* for the service of carrying exported electricity from *embedded generation units.*

- The amendment of clause 6.18.5 (g) (2) to make it clear that the consideration of the revenue to be recovered from each distribution tariff must take account of the effect of any credits provided due to the LGNC proposed here with respect to the ability of the distribution network service provider to recover its efficient costs in providing the service while also minimising distortions to the price signals provided in its pricing.
- The addition of a new clause 6.20.1 (a) (1) (ii) to include a credit associated with any negative tariff in respect of an *embedded generating unit* as an item that must be included where applicable in a bill for distribution services to an *embedded generator*.
- The addition of a new clause 6.20.1 (a) (2) (v) to include in the determination of the charges to be levied against a Distribution Customer any credit applicable to the Distribution Customer as determined under relevant negative tariffs in respect of the Distribution Customer's *embedded generating unit*.
- The addition of a new clause 6.20.1 (j) to make explicit the requirement that where a bill is negative due to the application of a negative tariff or other credit, the absolute value of that amount represents an amount that (a) must be paid by the *Distribution Network Service Provider* to the *network service user*, and (b) that must be paid on the date that the bill would have been payable by the *network service user* had it been a positive amount.
- The addition to clause 6.20.2 (a) (4) of the phrase 'including any credit amounts' to make it clear that information on applicable credit amounts must be included on a bill for a *network coupling point* issued by a *Distribution Network Service Provider* directly to a *Registered Participant*.

## 3.3. Consequential changes to other parts of the Rules

The only consequential changes required to other parts of the Rules in order to implement the intent of the Rule change being proposed are the following:

- A change to Chapter 10 to add a definition of a *"local generator"* as a person that owns, operates or controls an *embedded generating unit*. This definition would apply to a local embedded unit of any size. This is distinguished from the definition "*Embedded Generator*", which is presently confined to Generators registered as a Participant under the Rules, and typically only encompasses generators of greater than 5MW nameplate capacity.
- A change to Chapter 10 to add a definition of "*Local Generation Credit Guidelines*".
- A change to Chapter 10 to add a definition of "*network service user*" as meaning "a person who is provided with an electricity network service".

## 3.4. Draft of the proposed Rule

Detailed changes to the Rules to support the implementation of the Rule change as proposed here are provided in Appendix A.

# 4. Statement of Issue

## 4.1. Overview

Everything else being equal, where an investment provides an economic benefit to society but the party facilitating the achievement of that economic benefit is unable to monetise that economic benefit, under-investment may occur and inefficient outcomes may[13] ensue.

The Proponents of this Rule change consider that local generators provide two types of benefits to distribution and transmission businesses that local generators typically cannot currently monetise, and therefore, everything else being equal, that this will lead to under-investment in smaller-scale embedded generating units and a less economically efficient electricity supply chain.

The benefits provided by local generators take the form of:

- Capacity support, if, as a result of the export of energy from these facilities, a network business (whether distribution or transmission or both) can be expected to incur a reduction in its future capital expenditure costs, most notably, as a result of being able to defer and/or reduce the size of its future network augmentation projects, and
- Avoided transportation costs, if, as a result of the export of energy from these facilities, a network business can be expected to incur lower on-going operation and maintenance costs.

In this context, the Proponents consider that:

- Small-scale local generators that export energy to the grid are, when considered collectively (i.e. as a portfolio), a feasible alternative to network augmentation for balancing supply and demand at the local level,
- Economic efficiency could be improved and it would be in the long-term interests of consumers to incentivise the use of local generation in circumstances where the cost of local generation exported to the grid is less than the cost of undertaking a network augmentation solution (whether distribution or transmission),
- At present, price signals within the electricity market may not accurately signal the benefits that local generators who export energy provide to network businesses, and therefore, everything else being equal, there may be under-investment in these types of facilities,
- The most efficient means of overcoming this market failure is, on the balance of probabilities, to create a Rule that ensures that distribution businesses must establish a local generation network credit (LGNC) that reflects the benefits the network receives from local generators who export energy[14], and
- The incremental costs of introducing such a cost-reflective network (credit) tariff for energy exported to the grid is likely to be small, hence on the balance of probabilities, any Rule change facilitating the introduction of such a tariff is likely to be consistent with the NEO.

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13 This will be dependent on the magnitude of any under-investment caused by the market distortion, and the costs of overcoming that market distortion.

14 We note that such a tariff is entirely consistent with the intent of the AEMC's recent determination in regard to *Distribution Network Pricing Arrangements*, which seeks to encourage more cost reflectivity in the structure of network tariffs. Signalling the value of the benefits accruing to the network from local generators that export energy to the network is the main intent of the proposed Rule change.

## 4.2. Capacity support

The required capacity of a distribution network is driven by the co-incident peak demands that a distribution business' customers place on the network. Where a distribution business forecasts co-incident peak demands[15] on its network – or a particular area within a distribution network – that exceed the capacity of that part of its network – the network business will generally either have to:

- build more capacity, with the cost of this generally being eligible for recovery via regulated distribution use of system tariffs[16],
- incur more "energy at risk" – that is, accept that there is a higher probability that the distribution network will be unable to service all of the energy that is demanded by its customers in that constrained location,
- purchase "demand response" from customers connected to the part of the distribution network that is constrained – that is, pay customers for the right to reduce their load at certain times, or
- purchase exported energy in the form of "network support" from generators connected to the constrained part of the system.

Everything else being equal, collectively, local generation facilities who export energy *may* be able to alleviate the need to transmit energy through certain parts of a distribution network (or parts of a transmission network). This can occur where those local generation facilities can be relied upon to inject energy into the grid at times when the network that they are connected to is peaking. If this were to occur, it *may* allow a network business to avoid future costs that it would have otherwise had to incur if those local generation facilities were not in operation. Therefore, it is the view of the Proponents that local generation facilities that export energy may provide an economic benefit which is cannot currently be monetised by those facilities.

As a result, the Proponents propose that the LGNC should:

- Be available to local generators of any size (not just larger generators embedded in distribution networks) as this increases the pool of embedded generators eligible to access the LGNC over and above those that would be of a sufficient size and scale to access existing schemes such as the Network Support Payments. Increasing the pool of eligible embedded generators also allows these embedded generators to be treated as a diversified portfolio, as opposed to being treated as individual generators providing network support in specific locations. This negates the need to have a specific contractual relationship (i.e., a guarantee of firmness) with each embedded generator regarding how much network support they will provide at certain times of the day/week/month/year.
- Be voluntary, in that generators should be allowed to choose whether or not to bear the costs of any metering changes required to facilitate any credit payments under the LGNC. This ensures that the upfront cost of implementation will be minimised, and moreover, if cost-reflective credit payments are signalled to local generators, they will only elect to take up the credit payment where those benefits (i.e., the value of the exported energy to network businesses which is reflected in the credit payment) exceeds the costs to the generator of obtaining that credit payment, and

15 Or energy requirements.

16 The extent to which such expenditure is able to be fully recovered will be dependent on whether the distribution business forecasts that capital expenditure as part of its regulatory submission.

- Be open to local generators who receive network capacity support payments for energy exported at times when the local network area is approaching the need for augmentation (including payments made under the RIT-D). However, any such payment under those schemes would need to reflect LGNC payments that may or would continue to be made to the embedded generator. In such cases, the network support payment or RIT-D payment would accrue at the difference between the SRMC and the LRMC of supply.

## 4.3. Avoided transportation costs

It is assumed that the cost of delivering electricity from central generation facilities is non-zero. Therefore, where local generation replaces the use of centrally generated electricity, this energy does not flow through the portions of the network infrastructure upstream of that injection, thereby avoiding any variable costs associated with those flows in the upstream portions of the network.

While some forms of local generation are eligible for and receive payments through feed-in tariffs, the value signalled to local generation proponents by these tariffs is the avoided cost of electricity generation in the wholesale market. These feed-in tariffs do not monetise any reduction in the variable transportation costs of the network infrastructure upstream of the local generation.

## 4.4. Specific issues in the existing Rules and how they would be addressed in the proposed Rule change

### 4.4.1. Lack of cost-reflective price signals, particularly those reflecting long-term benefits

The recent Rule change entitled *Distribution Network Pricing Arrangements* recognises that network pricing to date has not been as cost-reflective as possible, and has, amongst other things, changed the Rules from requiring that network prices 'have regard to' long-run marginal costs to a requirement that those prices be 'based on' long-run marginal costs.

It focuses on increasing the cost-reflectivity of network tariffs for consumption. This will encourage appropriate sizing, location and operation of small-scale embedded generators for the purpose of reducing consumption from the network. However, it does not:

- Explicitly address the situation where an end customer exports electricity into the grid. As a result, while such a customer may benefit from a network bill reduction where small-scale embedded generation replaces consumption of grid-supplied electricity, it is not clear that this customer can monetise the benefit of electricity exported to the grid where aggregate demand at the local level would otherwise require augmentation in upstream portions of the network infrastructure.
- Provide appropriate signals about the sizing, location and operation of small-scale embedded generators that could export energy to the grid when that energy could provide a benefit to the grid and therefore other electricity customers (as opposed to the sizing, location and operation of such systems for the purpose of reducing consumption from the grid, which is likely to be addressed by the *Distribution Network Pricing Arrangements* Rule change.

Furthermore, we note that both network businesses and embedded generators are faced with the need to make long-term investment decisions. In this regard, the requirement for distribution businesses to publish tariffs that reflect the value of electricity injections at times of local network peak demand in terms of their ability to reduce investment in long-lived assets will assist in the transition that will be required to the bi-directionality that will characterise the operating environment of the NEM's distribution networks. In doing so, the Rule change will increase dynamic efficiency thereby enhance the long-term interests of consumers.

### 4.4.2. Current 'gaps' and market failures

While the current Rules may facilitate efficient investment in larger-scale embedded generation, it is the Proponents' view that there are significant 'gaps' (or market failures) with regard to the provision of efficient investment signals for smaller scale embedded generation that this Rule change seeks to overcome.

These gaps/failures include:

- High transaction / administrative costs – smaller embedded generators are unlikely to be able to access any of the benefits they provide to network businesses as a result of their export to the grid because these benefits to the embedded generator are likely to be small relative to the administrative costs the embedded generator would have to incur in entering into bespoke arrangements required in order to receive Network Support Payments, and
- Requirements for firm capacity in an individual contract – small embedded generators are likely to find it difficult to impossible to provide a 'firm' guarantee of capacity support (which is likely to be a pre-requisite for the receipt of Network Support Payments), despite the fact that on a probabilistic basis (i.e., when treated as part of a broader portfolio of capacity support), their ability to provide capacity support could be quantified.

### 4.4.3. Restrictive nature of the definition of end consumers as electricity customers or retail customers

The use of the defined terms *electricity consumer(s)* and *retail customer(s)* in various parts of Chapter 6 of the Rules does not recognise the potential for an electricity consumer or a retail customer to also provide services to the network through the operation of an embedded generation unit.

The proposed Rule change would address this by substituting the defined term *network service user(s)* for the terms *electricity consumer(s)* or *retail customer(s)* in those clauses of Chapter 6 in which meeting the intention of the clause and this proposed Rule change requires that it apply to an end customer that operates an embedded generation unit in addition to being a consumer of electricity.

The proposed Rule change also provides a definition of a *local generator* as 'a person that owns, operates or controls an *embedded generating unit*'. The purpose of this is to ensure that the intentions of the Rules (and particularly those of clauses 6.18.4 and 6.18.5) are applied to embedded generators, including those that are not registered as "Embedded Generators"..

# 5. How the proposed Rule will contribute to the achievement of the National Electricity Objective

Section 7 of the NEL outlines the National Electricity Objective (NEO). It states that:

> *The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to–*
>
> *(a) price, quality, safety, reliability and security of supply of electricity; and*
>
> *(b) the reliability, safety and security of the national electricity system*

The NEO reflects the concept of economic efficiency, which has three sub-components: *productive*, *allocative* and *dynamic* efficiency, and guides the assessment of Rule change proposals.

In brief, those components and their relationship to the NEO can be described as follows:

- **Productive efficiency** ('promote efficient investment in'): The least cost mix of resources should be used to deliver electricity services.
- **Allocative efficiency** ('*efficient….use of, electricity services*'): Tariffs for regulated services should be reflective of the forward-looking costs of providing those services (cost reflective), so that the price signals created lead to the most efficient allocation of scare resources; and
- **Dynamic efficiency** ('*for the long term interests of consumers of electricity with respect to…price*'): Regulated businesses should be incentivised to seek out efficiency gains over time, and improve performance where the benefits exceed the costs, such that efficiency is promoted in the long-term.

In this context, it is important to understand what economic benefits accrue from the installation of local generation, and their overall magnitude, as this assists in framing the discussion concerning who the credit for exported energy should be paid to, and how it should be paid to them.

In theory, two economic benefits may potentially accrue from providing some form of economic incentive to local generators to export energy that in turn provides network capacity support (or avoids the need to transport energy). These are:

- **Productive efficiency:** where a cost-reflective tariff mechanism promotes increased production of electricity (or capacity support) from local generators it might promote more efficient sizing, location and operation of local generators within the distribution network, such that the cost of providing network services is reduced for the long-term benefit of consumers, and
- **Allocative efficiency:** where a cost-reflective tariff mechanism results in lower network costs that flow through to lower network (and therefore retail) prices for the long-term benefit of consumers, it will promote more efficient consumption of energy services, which in turn would increase consumer and producer surplus.

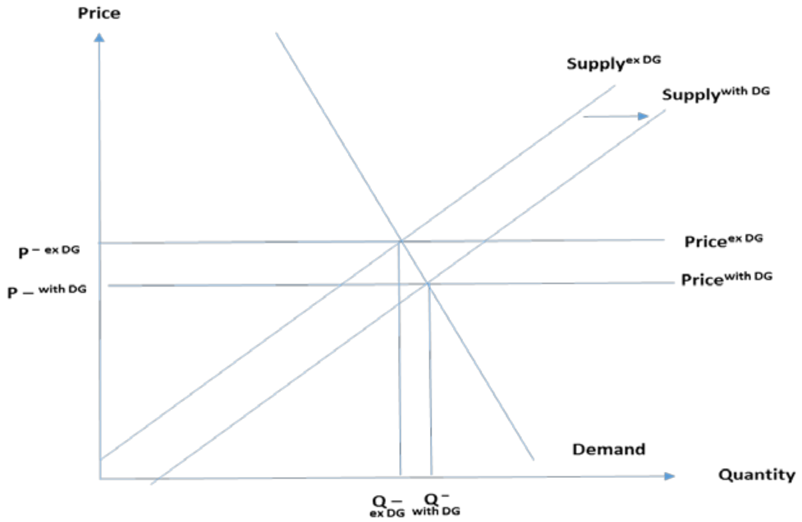
Productive efficiency, in the context of a network business, is a relatively easy concept to understand. If embedded generation that exports energy represents a cheaper means of balancing supply and demand during peak demand periods within the distribution network(or the related transmission network), or it means that a network business' costs will be lower as a resulting of not having to transport energy through its entire network (relative to if that energy was generated by a conventional, centralised electricity generator), then its adoption will lower the overall costs to the network business of providing electricity services, and therefore, it will (a) tend to put downward pressure on network prices and (b) lead to more efficient outcomes[17].

Allocative efficiency effectively seeks to increase the total economic benefit (i.e., the sum of the benefits that accrue to both producers and consumers) from the reduction in final prices stemming from a change in the production function.

To illustrate these concepts, the supply/demand diagram below outlines what would happen if a tariff that offered an LGNC facilitated the entry of local generation into the market, and the export of energy from this facility led to a reduction in the overall cost of providing network services.

Firstly, the supply curve moves to the right, as at every quantity, the overall cost of supply is lower. This then leads to lower overall price levels (because of lower production costs), and a greater quantity demanded (because as the price of electricity services reduces, the demand for that service increases).

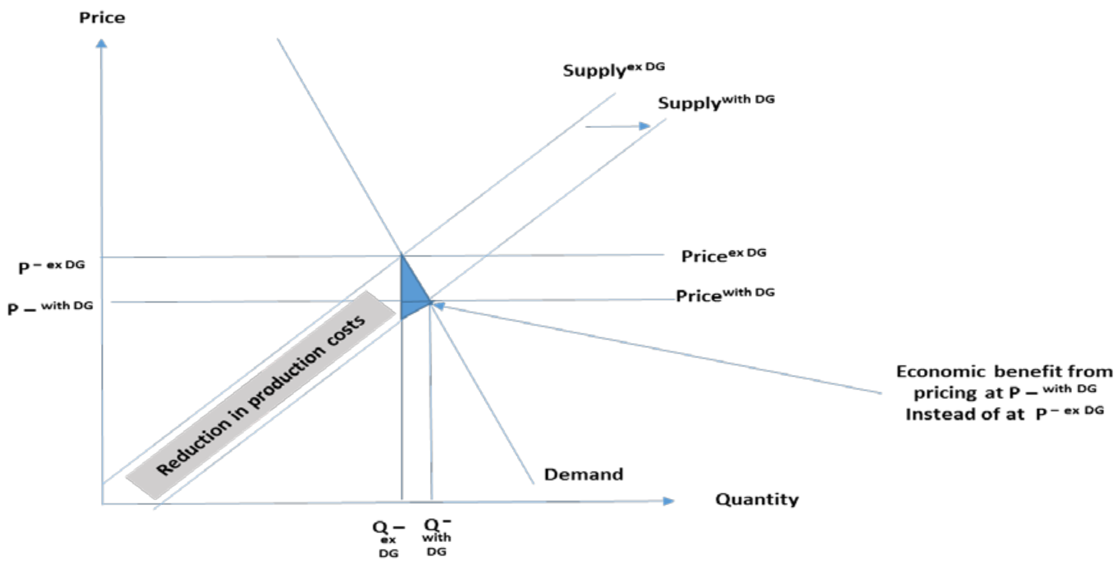
Figure 1: Supply curve moves to the right due to increased reliance on exported energy from lower-cost local generation




The next figure highlights the economic benefits of the above outcomes.

17 Except to the extent that any reduction in costs to a distribution network is offset by higher costs in other parts of the electricity value chain.

Figure 2: Economic benefit of enabling lower cost embedded generation




In simple terms, the above diagram illustrates that the benefits of enabling lower-cost local generation are the lower production cost benefits, and the increase in consumer and producer surplus resulting from the change in the final price of electricity services (represented by the blue triangle).

Another way of looking at it is that if the lower production costs stemming from the entry of lower cost local generation are not signalled to end customers by way of lower prices[18], and therefore, price is higher than the true marginal cost of supply, customers will not consume enough of the service attribute (i.e., some customers will *NOT* consume electricity services, despite the fact that the cost of providing them with an incremental unit of that service attribute *is less than* the incremental benefit they would receive from consuming that additional unit)[19]. This loss in allocative efficiency is termed a deadweight loss. As is illustrated in the above diagrams, the quantum of the deadweight loss is a function of:

- the magnitude of the difference between the actual price charged and the cost-reflective price (i.e., the difference between $p_{-}^{\text{ex DG}}$ and $p^{\text{- with DG}}$), and
- the elasticity of demand for that service attribute (the slope of the demand curve).

18 In the context of our assessment, this would involve utilising an LGNC (reflecting the benefits provided by the generation facility to the network business) being paid directly to the owner of the generation.

19 Conversely, if the marginal price is less than its true cost, too much consumption of the service attribute will occur (i.e., some customers will consume electricity services despite the fact that the cost of providing them with an additional unit of that service attribute exceeds the benefit that they receive from consuming that service attribute).

# 6. Why the network benefit should be paid to local generators

Given that there are two potential economic benefits, it raises the possibility that lower production costs stemming from energy exported from small-scale local generation could be signalled to end customers in either of two ways. The benefit could be paid:

- to end customers who have entered into arrangements to purchase locally produced energy, via a lower distribution tariff. This approach has been termed Virtual Net Metering. It contrasts with the purchase of energy that is produced via a centralised generation system that in turn requires the distribution of that energy through electricity networks comprising various voltages; or
- to local generators, via the LGNC.

Whilst the Proponents acknowledge that signalling the economic benefit to end customers who consume locally produced electricity may[20] improve allocative efficiency benefits, this needs to be considered in the context of:

- the demand for electricity being relatively inelastic[21] (i.e. a 1% increase in price leads to a less than 1% reduction in demand), which, everything else being equal, means that the loss in allocative efficiency from not signalling this directly to end customers of that locally produced electricity is likely to be very small, and
- the relatively small magnitude of the reduction in production costs (from a network perspective) because:
  - any capacity support benefit will only reflect the long-run avoided capacity and operational costs in the *parts of the network that are upstream of the local generator*[22] and
  - generation during non-peak times only avoids short-run operational costs (i.e., costs that would have otherwise been incurred in parts of the network upstream of the embedded generator in transporting that energy from centralised generation locations), which, given the nature of electricity distribution services, is likely to be small.

Therefore, the magnitude of the “over-charging”[23] of the end customer that consumes electricity from a local generator is likely to be small in the context of the overall price signal, particularly in non-peak periods, even where notionally cost reflective tariffs (tariffs that reflect the cost of centrally produced energy) are in place.

Furthermore, there are three other factors that contribute to the Proponents’ view that the lower production costs stemming from exported energy from local generators should not be signalled directly to end customers via lower prices for locally generated electricity, but rather, to generators via an LGNC.

These factors are as follows:

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20 The reason for the use of the word ‘may’ reflects the three other factors that are mentioned later on in this section.

21 As reflected in virtually all of the publically available literature on this issue.

22 For example, if an embedded generator is connected to the LV network, then in simple terms, the benefit of any capacity support it provides will be experienced in the HV and sub-transmission networks.

23 Due to the lower production costs stemming from embedded generation not being signalled to end customers.

- It could be argued that requiring distribution businesses to nett off any exported generation against the network component of a final customer's network bill would require that business to provide a service that could otherwise be provided by the market. For example, there is nothing to our knowledge that would limit a third party (e.g., a Retailer, or the generator itself) effectively[24] netting the credit payments made to the generator, from the network bill of one or more end consumers that are 'linked' (e.g., by contract, or via common ownership) to that embedded generator. In this situation:
    - imposing this obligation on the distribution business could preclude other, potentially more efficient service providers from entering the market to provide this retail service, and
    - there would in fact be no gain in allocative efficiency, as the market would facilitate provision of the correct price signal to end customers (it is just that it would be done by a third party, not by the distribution business).
- Further, imposing this requirement on distribution businesses may add significantly to the costs of introducing such a tariff, which will be a key consideration as to whether this proposed Rule change is in accordance with the NEO (as the NEO will not be considered to be "promoted" if the costs of implementing and administering the proposed Rule exceed the economic benefits that are identified as accruing from that Rule change).
- The regulatory process will provide for the passing through of the lower costs stemming from the more efficient use of exported energy from embedded generation to all customers via network tariffs. Therefore, if the elasticity of demand (slope of the demand curve) of the customers consuming exported energy from local generators is the same as that of the distribution business' broader customer base, there will be no loss in overall allocative efficiency.

24 This could be done outside of the 'electricity bill', for example, by providing a separate (credit) invoice to the 'linked' customer for their share of the amount of the credit payment made to the embedded generator.

# 7. Benefits and costs of the proposed change

The following table highlights the expected benefits and costs of the proposed Rule change, relative to the status quo.

Table 1: Economic benefits and costs of the proposed Rule change[25]

| Participant | Benefit | Cost |
|---|---|---|
| Distribution businesses | More efficient location, sizing and operation of local generators who export energy to the network, thereby facilitating more efficient:<br>• balancing of supply and demand on the network resulting in potential deferral of augmentation expenditure,<br>• use of the network potentially resulting in the avoidance of variable electricity transportation costs, and improved utilisation of existing assets, and<br>• investment in augmentation required to cater for bi-directional flows | Possible cost of billing system changes in the event that the distribution business' billing system does not have the required functionality (e.g. where a distribution business has never offered time-differentiated prices or feed-in tariffs)<br>Incremental cost of having to develop a LGNC (e.g., administrative costs, modelling, communications) |
| Transmission businesses | Deferral and/or reduction of augmentation and replacement capital expenditure (over the longer term)<br>Avoided variable electricity transportation costs | None |
| Local generators | Producer surplus provided by the ability to monetise the value of benefits provided to the network in the form of a long-term price signal<br>Reduced costs to small-scale embedded generators who in the absence of the credit might be incentivised to make investments in things such as battery storage to maximise the value of their investment in generation facilities rather than exporting that energy to the grid where it could be of greater value | Potentially the incremental cost of interval metering[26] |
| Other consumers | Lower network charges in the long term and possibly in the short term | Possibly higher network charges in the short term[27] |
| Retailers | Potential for competitive advantage through differentiation of the retailer's market offers | None, assuming that the pass-through of the LGNC is allowed to be market driven |
| Generators | Reduced fuel and operating costs<br>Possible reduction in future capital expenditure requirements | None |
| Society | Potentially lower environmental externalities to the extent that the small-scale embedded generation that is installed has lower emissions intensity than the centrally generated electricity | Potential for increased emissions and noise from electricity generation close to end-use customers |

25 Note that the benefits and costs listed are incremental to benefits and costs provided by existing Rules including recent Rule changes.

26 In some jurisdictions, local generators must already install such metering.

27 Whether the LGNC produces upward or downward pressure on network tariffs in the short term depends on whether SRMC is greater of less than LRMC.

It is unlikely that the implementation costs of the proposed Rule change will exceed its benefits, given the design of the LGNC as proposed in combination with the impact of other recent Rule changes (and most particularly the *Distribution Network Pricing Arrangements*). Specifically,

- The use of LRMC and the proposed definition of the credit as applying to energy exported by small-scale embedded generators at times of network system or local area peak demand matches the benefit to the economic effect it has on the network (and therefore other users).
- The costs that distribution businesses (or transmission businesses) would be likely to incur to respond to the proposed Rule change would in most cases be simply an extension of the costs they will incur in order to comply with the Final Determination of the *Distribution Network Pricing Arrangements* Rule change concerning distribution system pricing arrangements. As a result, the incremental costs of the proposed Rule change are almost certainly going to be quite modest[28].
- Most network businesses have feed-in tariff arrangements already, therefore, there are likely to be limited changes required to their billing systems. This limits the incremental costs to the distribution business of implementing an LGNC.
- Most existing embedded generators already have the appropriate metrology in place to support the introduction of an LGNC[29]. Furthermore, new embedded generators would, under this Rule change, have to fund the costs of metering, and therefore would assess whether the benefits to them of implementing the appropriate change in metrology exceed the costs. This in turn is consistent with the Draft Competition in Metering Rule change, which would allow customers to choose their metering provider based on their assessment of the benefits and costs of switching providers.

For these reasons, the Proponents believe that it is likely that the financial costs of implementing this measure will be relatively small, and are unlikely to exceed its economic benefits or impose higher costs on other customers over the long term. We note that trials currently being undertaken are expected to provide information on the costs of providing an LGNC price signal.

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28 As discussed earlier, the exception may be where a distribution business has never implemented any form of time-differentiated pricing and therefore may require modifications to be made to its billing system.

29 Note, however, that care should be taken in focusing solely on existing embedded generators when considering the impact of the proposed Rule changes, as it can be argued that most of the economic benefits come from facilitating the appropriate location, sizing and operation of new generation facilitates.

# Appendix A: Detailed changes to the Rules to support the proposed Rule change