PROPOSED LOCAL GENERATION NETWORK CREDIT RULE CHANGE

Response to AEMC Consultation Paper – ERC0191

4 February 2016

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EXECUTIVE SUMMARY

The ENA welcomes the Australian Energy Market Commission's (AEMC) Consultation Paper *National Electricity Amendment (Local Generation Network Credits) Rule 2015* (Consultation Paper) released on 10 December 2015.

Support for incentives for efficient embedded generation deployment and use

ENA strongly supports a coordinated national regulatory and pricing framework that promotes efficient investment and usage decisions throughout the energy chain, including electricity transmission and distribution networks, gas networks and embedded generation. The efficient investment, in and use of, embedded generation has material benefits to both consumers and energy networks.

This means that this ENA response to the proposed rule change is focused not on the principle of whether the provision of network credits to local embedded generators is appropriate, but rather on whether the specific rule change proposal made by the proponents, with its mandatory nature, features and characteristics is likely to promote the long-term interests of consumers.

Sequencing network pricing reforms critical

ENA has been active in publicly promoting the consumer benefits of a sequenced package of network pricing reforms, including through the recent distribution network pricing rule change. ENA members are currently in the process of developing, refining, consulting upon, and seeking approval of a 'first wave' of reformed network pricing structures (through the Tariff Structure Statements processes, for example). In this 'first wave', the timely implementation of more cost-reflective network tariffs, with close customer engagement, can make electricity bills fairer by removing inequitable cross-subsidies among customers and providing more efficient signals for efficient investment in network infrastructure and distributed energy resources, such as embedded generation, storage and demand management.

It has been widely recognised by the AEMC and other experts that without more cost-reflective network tariffs, there are effectively distorted incentives to install some forms of embedded generation (among other technologies). Such distortions should be recognised prior to considering further changes to incentives for embedded generation.

In the future, network businesses consider there may be a role for forms of network credit schemes to be developed and implemented as part of a fully integrated package of sequenced "second wave" pricing reforms. Such second wave incentive frameworks could equally include frameworks to encourage a variety of distributed energy resources and there are a variety of alternatives to a local generation network credit scheme. Critically, provided the network and regulatory pricing frameworks provide the right incentives, networks consider there is no compelling reason why such developments should require or rely on new mandated regulatory intervention through the rule change process.

Assessing the rule change against the rule-making test

ENA considers that the proposed rule change as it currently stands is not likely to be consistent with the promotion of the *National Electricity Objective* (NEO).

A key reason for this is that the rule change fails to adequately consider the combined impact of the existing (and recently expanded) suite of measures and incentives in the NER framework that contribute to fostering efficient investment in, and use of, embedded generation.

Risks to consumers of 'regulatory overlay'

A critical issue for further consideration by the Commission is the relationship of this measure to other existing rules, incentive schemes and jurisdictional measures. Unless carefully designed, a local generation network credit scheme could risk producing higher cost, inefficient outcomes when as proposed in the rule change it would be simply overlaid on current policy, regulatory and pricing settings. It creates the risk of introducing a set of artificial, regulator-determined and likely highly averaged pricing signals ***prior to*** addressing the existing distorted signals for investment through network pricing reforms under the AEMC's Distribution Network Pricing arrangements. .

Implementation of a mandated network credit scheme in the presence of, for example, an existing range of inefficient cross-subsidises between consumers who do not own embedded generation and those that do would compound existing unfair cross-subsidies and distortions in investment and usage signals - which would impose costs on all energy consumers

Design and implementation issues

The scheme as proposed by the proponents also faces a range of significant conceptual design and implementation challenges. These include:

- whether the savings credited as part of the rule proposal can accurately estimated and be captured in practice or whether customers could risk 'paying twice' for the same generation;

- determining a local credit which is sufficiently targeted and flexible that it avoided creating inefficient investment or usage signals given likely limited advanced meter penetration beyond Victoria;
- how such a credit would be varied or removed over time as the realisable network value delivered by the embedded generation changed over time (through different phases of network asset lives, for example);
- avoiding a measure which resulted in a net transfer of value, rather than increased efficiency, with the attendant risk of creating a set of narrow set of beneficiaries from new or expanded cross-subsidies paid by other users

A review of these issues, and the limited number of comparable schemes or export credit arrangements by Frontier Economics (Attachment A) that are in place internationally highlights that these challenges have not yet been adequately overcome. Rather, international experience demonstrates that regulators are increasingly seeking to as a first step recognise and fully assess the full range of costs and benefits from embedded generation.

A further relevant issue to be considered in assessing the potential costs and benefit of the rule change is that within many unconstrained areas of Australian distribution networks, additional embedded generation is likely to deliver low or negative savings to networks (i.e. additional embedded generation may impose net costs, rather than avoid them).

Proposed way forward

Conceptually, to avoid introducing scope for increased cross-subsidies between consumers, a future pricing environment would need to feature the achievement of a satisfactory level of cost-reflective tariffs as a foundation.

For these reasons, ENA considers that the AEMC determination should not approve the rule. Rather, the AEMC should undertake active monitoring and advice to the COAG Energy Council as part of its ongoing market development and advisory functions and seek to provide regular and published assessments to the Energy Council of:

- progress on network tariff reform, including the removal of existing known cross subsidies created by highly volumetric-based charging methodologies
- the performance of the existing National Electricity Rule mechanisms which provide existing incentives for efficient embedded generation deployment
- barriers to the emergence of voluntary, fit-for-purpose, network business led 'second wave' reforms including not only local generation network credit programs, but also critical peak pricing measures, and demand management response initiatives (See Figure 1 overleaf).

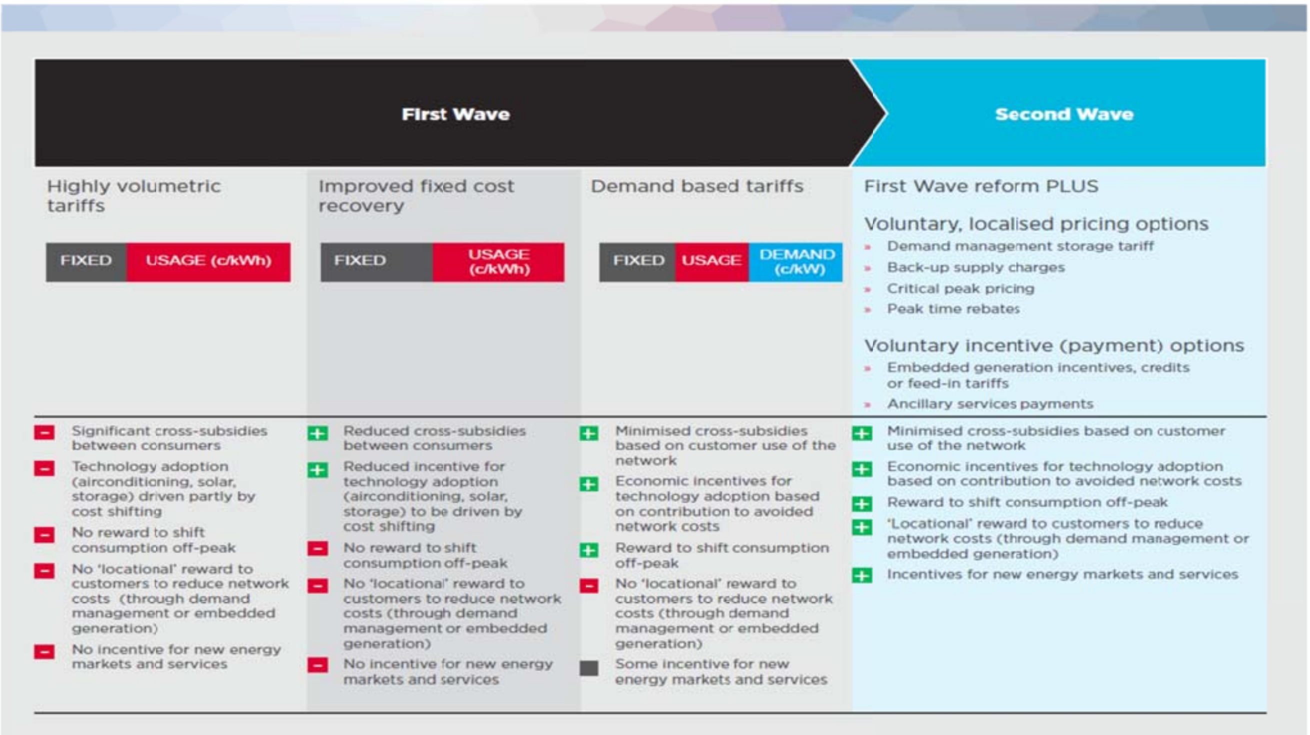

Figure 1 - Two 'waves' of tariff reform to 2025

CONTEXT FOR NETWORK CREDITS PROPOSAL

DRIVING EFFICIENT EMBEDDED GENERATION INVESTMENT

ENA strongly supports a coordinated national regulatory and pricing framework that promotes efficient investment and usage decisions throughout the energy chain, including electricity transmission and distribution networks, gas networks and embedded generation.

Efficient deployment of embedded generation within networks is supported by network businesses because it can:

- » assist individual network customers meet their specific energy needs;
- » support an emerging 'transactive' energy market allowing local and peer-to-peer energy trading and greater customer choice;
- » help support a resilient and reliable grid
- » potentially deliver lower costs to all network customers by deferring specific augmentation or expansion projects;
- » allow investment in gas and electricity networks to be efficiently 'co-optimised' to lower the overall costs to the community; and
- » leverage the value to the community of existing energy network infrastructure.

Over the long-term Australia's electricity systems are increasingly likely to see responsibility for key investment decisions about electricity infrastructure move from a few large entities, like generators and network service providers, to millions of individual consumers. Consumers will enjoy expanding greater choices about how they produce and consume electricity and will make decisions whether to invest in embedded generation like solar PV or a range of gas technologies, or access them (for example through community schemes) based on financial and other benefits they value.

Most analysts expect this dynamic environment will continue to rely on electricity networks as enabling platforms for how consumers generate, store and use electricity. The success of such a transformation will depend upon consumers receiving efficient signals about the true cost of these choices.

Continuing implementation of network tariff reform is critical to ensuring the fair and efficient operation of electricity networks as integrated enabling platforms as Australian consumers either acquire distributed energy resources or access them through community schemes.

The more effective the economically efficient integration of distributed energy resources into the network, the greater the opportunity to reduce future network costs while ensuring grid resilience and reliability for the ultimate benefit of consumers.

Consumer choices should determine the nature and extent of efficient future investment in network capacity. Where customers respond to more cost-reflective network tariffs by:

- increasing their reliance on network capacity then networks will increase their efficient investment in the network in order to continue to meet peak demand; and
- decreasing their reliance on the network capacity and instead acquire or access DERs, then networks will decrease their efficient investment in the network.

Network tariff reform will therefore inform and encourage efficient decisions about future investment in both the network and new technologies as the relative costs and benefits of each are made transparent. Customers will have more control over the extent of network investment and ultimately, the level of network tariffs.

CAPTURING BENEFITS THROUGH SEQUENCED REFORM

Fairer, more efficient electricity network prices should provide significant benefits in lower electricity bills, avoided cross-subsidies and stronger incentives for efficient investment in network infrastructure, distributed energy resources and smart technologies.

While the reforms being currently implemented will provide improved signals for new service providers, the full optimisation of DER and smart technologies is likely to require a "second wave" of price and incentive reforms through to 2025. These further reforms are likely to see diverse choices, which may offer customers the opportunity to participate in new pricing options or markets.

It is possible that these "second wave" pricing and incentive reforms will occur through voluntary participation, have location-specific features and be dynamic in time. Such frameworks critically depend on, and are informed by, the effective implementation of the "first wave" of reforms.

That is, for positive outcomes to be achieved, reform must be carefully sequenced in a way that does not promote inefficient investment or usage signals to be created, or existing identified cross subsidies (for example, arising to be exacerbated.

Following the Commission's network pricing reforms finalized in 2015, Australian energy markets can be characterised as entering a 'first wave' of pricing and tariff reform (See Figure 1). The focus of this first wave is providing clearer signals, recognizing the need for transition pathways and customer impacts, which align network charges to long-run marginal costs. In particular, a number of networks are now proposing the introduction of demand-based pricing elements within new tariff structures.

ENA considers that the development of voluntary network local generation credit schemes represents a reform that should be considered only subsequent to meaningful progress on the 'first wave' of network pricing reforms. This is because:

- it has been widely recognised by the AEMC and other experts that without more cost-reflective network tariffs, there are effectively distorted incentives to install some forms of embedded generation (among other technologies);
- the introduction of network credit payments in the absence of network charging better reflecting underlying costs has the potential to introduce inefficient investment and usage decisions, potentially resulting in higher prices and stranded customer investments in embedded generation;
- pursuit of local generation credit schemes could then proceed alongside the range of series of "second wave" linked initiatives and reforms, and form part of a comprehensive reform and internally consistent reform package.

In the case of the proposal to introduce a local network credit scheme this means that there should be a careful and deliberate focus by policy-makers and the Commission on the impacts of bringing forward by regulatory fiat a single (relatively complicated and advanced) element of 'second wave' network pricing reforms and advancing it in isolation.

RULE CHANGE PROPOSAL

PROBLEM IDENTIFICATION

On 15 July 2015 the AEMC received a rule change request from the City of Sydney, Total Environment Centre and the Property Council of Australia (proponents).

In summary, the rule change proposal is aimed at imposing a requirement on distribution network service providers (DNSPs) to offer embedded generators a Local Generation Network Credit (LGNC) for energy that is exported back to the grid.

In particular, the proponents argue there is a shortcoming in the existing NER because they do not provide the appropriate pricing incentives in cases where customers with embedded generation become net exporters of electricity to the grid. The proponents argue that the LGNC would ensure that customers contemplating to invest in embedded generation that may lead to them becoming net exporters of electricity to the distribution network will face efficient price signals.

Electricity networks are playing an increasing role in managing and integrating an increasing pattern of 'inflows' and 'outflows' from a variety of distributed energy resources and connections. As this role develops this could have implications for the recovery of costs to be extended to all distribution network users, based on generation and consumption, rather than solely falling on consumption as it currently does under the existing *National Electricity Rules.*

The ENA does not agree, however, with the proponents that there is any currently any established material deficiency in the NER with respect to small-scale embedded generation. An examination of the existing regulatory mechanisms for DNSPs under the current Chapters 5 and 6 Rules does not support the proponents' contentions.

ASSESSING THE EXISTING FRAMEWORK

CURRENT RULES FRAMEWORK

The starting point for assessment of any rule change proposal should be a careful assessment of the existing regulatory framework and whether the policy objectives sought by the proposal that are consistent with the NEO are being be achieved through the existing provisions and discretions under the NER.

Given the wide ranging and relatively recent reforms to the regulatory framework for embedded generation (particularly a number of rule changes from the *Power of Choice* review), the ENA considers that the proponents' proposals would not result in demonstrably superior outcomes for the long-term interests of consumers, because they do not adequately take into account relevant features of the regulatory framework as it currently stands and operates.

There are a number of mechanisms within the regulatory framework that facilitate integration of non-network solutions if it is cost effective to do so. These mechanisms include:

» **Connecting embedded generators rules (Chapters 5 and 5A)**. A transparent connection process for large and small embedded generators, with defined time-frames and requirements on the part of the DNSPs to disclose relevant information enables the efficient connection of embedded generators across the National Electricity Market.

» **Avoided Transmission Use of System (TUoS) charges**. DNSPs are required to make payments to embedded generators that reflect the cost component that would have been payable to the transmission network service provider had an (eligible) embedded generator not been connected to the network. This payment may apply to small embedded generators where the applicant is eligible, and seeks to negotiate, its connection under Chapter 5 of the NER.

» **Network support payments**. Network support payments can be and are negotiated between DNSPs and embedded generators to reflect the economic benefits the embedded generator is providing to the DNSP. Under these arrangements, which are in place across a number of jurisdictions, embedded generation can be contracted by a DNSP to address network constraints. As an example, a single Victorian network business already has direct network support arrangements with embedded generators with an installed capacity of around 60 MW.

» **Distribution network planning and expansion framework**. The current network planning arrangements in the NER require the network businesses to apply the RIT-T and RIT-D before augmenting their networks. These tests require alternatives to be considered to network augmentation, which should include both network and non-network options, including embedded generation.

- **Demand Management Incentive Scheme (DMIS).** This recently revised mechanism specifically encourages trials of innovative non-network options by DNSPs that benefit customers through reduced costs over time. While the revised DMIS is expected to be developed by 1 December 2016, electricity network businesses already deliver innovative projects under the existing *Demand Management Innovation Allowance* in accordance with demand management objectives. Innovation allowances are currently included within the network determinations applying to all electricity distribution businesses.
- **Small generation aggregator framework**. This framework reduces the barriers to small embedded generators participating in the market by enabling them to aggregate and sell their output through a third party (a Market Small Generator Aggregator). This makes it easier for these parties to offer non-network solutions, and for DNSPs to procure those options when it is efficient to do so.

Based on the examination of the existing and recently enhanced regulatory mechanisms setting the framework for embedded generation investment under the current Chapters 5 and 6 of the NER, the ENA considers that there is no compelling case for the change in the form proposed. As such, the ENA considers that the current NER mechanisms contribute to the achievement of the NEO and foster efficient investment in, and use of, embedded generation.

INTERACTION WITH JURISDICTIONAL SCHEMES AND PRICING MEASURES

The ENA notes that in addition to these existing rule mechanisms, network pricing signals are further impacted by a range of bespoke state-based regulatory and pricing arrangements. These are not uniform across jurisdictions in the National Electricity Market.

Examples of these include mandated solar feed-in tariffs, and jurisdictional limitations on the scope of cost-reflective network pricing. In addition, jurisdictional review processes underway in Queensland by the Queensland Productivity Commission and Victorian Essential Services Commission are also currently examining valuation of distributed generation and have the potential to make relevant policy recommendations to governments.

It is currently unclear how any proposed rule would interact with any potential arrangements arising from these processes, or what mechanisms would be available to ensure that the combined effect of these rules would not lead to outcomes that distorted efficient investment signals in embedded generation.

CONCEPTUAL DESIGN ISSUES

The ENA agrees with the AEMC that the question that needs to be addressed in the first instance is whether there is an issue with the existing provisions of the NER. The previous section has addressed this question and concluded that a number of mechanisms in the NER incentivise market participants to invest efficiently in and procure efficient levels of embedded generation.

However, there are several issues raised by the design of rule change proposal that warrant further comment.

ASSUMPTIONS UNDERPINNING PROPOSED SOLUTION

The proponents' rule change proposal appears to be based on two assumptions. First, it assumes the long-term savings (if any) in network costs from distributed generation can be captured with a high probability.

Second, it assumes that it is sufficiently feasible to determine an LGNC that would represent the appropriate network price signal for exported energy.

The ENA considers that designing a regulator-mandated distribution credit so as to send efficient price signals to embedded generators would be very difficult, if not impossible. This is because there are some practical limitations that substantially constrain the capacity for any LGNCs to achieve the intent as contemplated in the rule change proposal. These include:

- It would be very difficult to calculate the direct benefit from distributed generation to distribution networks, in terms of avoided investment, which is a key input in designing the LNGC or any alternative solution;
- Network costs are driven by peak demand at a particular location. It is unlikely that LGNCs to embedded generators can be designed to fully reflect the locational characteristics. The lack of advanced

metering and intra-network pricing for distribution networks would represent key barriers;

- In an environment of low peak demand (and low values of LRMC) any "fair value" of solar is likely to have a low or no network value of solar (other than where there may be a network peak constraint) the main components in the value attributable to small-scale solar energy accrues to the individual consumer or retailer through avoided energy purchase costs and avoidance of electricity (transmission) losses;
- The impact of embedded generation on network costs is further complicated by the fact that there are significant interdependencies across the supply chain that drives incentives to invest in embedded generation;
- With rapidly evolving technology and innovation, the methodology and input assumptions for calculation the LGNCs would need to be reviewed on a regular basis.

The ENA supports adequate incentives for deployment of efficiently scaled distributed generation, for example, in locations where networks are currently constrained.

Given the current constraints on cost-reflective and locational pricing signals, however, is highly unlikely that regulator set LGNCs would provide sufficiently accurate price signals that better encourage the installation of embedded generation to relieve localised network constraints.

In addition, the ENA notes that networks have not been designed to handle large export power flows at the distribution level. In some instances high penetration levels of distributed generation may result in additional network augmentation costs which exceed broadly estimated or assumed network benefits.

In this regard, the AEMC correctly directs stakeholders' attention to the fact that if the calculation of the long-term avoided network costs is not sufficiently accurate, then the LGNCs are more likely to send inappropriate price signals to embedded generators, thereby encouraging inefficient investment decisions.

If this is the case, the overall effect of the LGNCs is likely to increase networks total costs, leading to higher network charges for consumers and inefficient cost stranding on the part of networks, adding to regulatory risk. These outcomes are contrary to the *National Electricity Objective*.

Based on the above, there is a real risk that the proponents' proposal will drive outcomes that are directly inconsistent with the NEO.

SETTING THE PROPOSED CREDIT: TRANSFER OR EFFICIENCY GAINS?

The AEMC correctly observes that a negative tariff suggested by the proponents does not appear to generate any additional efficiencies or net economic gain. This is because setting the LGNC to reflect the entire expected reduction in long-run network and operating costs brought about by EG, it would imply EGs receive (or monetise) all the network benefits of EG, from leaving final customers no better off.

The ENA considers that such a credit design, if implemented, would not provide efficiency benefits to energy consumers at large, or society.

In theory, a distribution credit to embedded generators would only be efficient from the perspective of society if the total network costs, including the cost of estimating and administering the scheme, and the credit itself, are less than the costs that a DNSP would have incurred to meet demand in the absence of energy exported by small-scale embedded generators. If there is not a net reduction in costs, the scheme has not provided benefits compared to the status quo. .

NEW AND EXISTING INVESTMENT IN EMBEDDED GENERATION

The AEMC has asked whether it is appropriate to draw a distinction between new and existing investments in embedded generation.

It is important to emphasise that only future network costs can be influenced by the introduction of any LGNCs. Therefore, the answer to the AEMC's question will depend on whether these future costs can be influenced by the behaviour of the existing embedded generators.

The ENA considers that it is unlikely to be the case. Therefore, it would not appear to be efficient to include price signals with respect to existing investment in embedded generation.

ADMINISTRATIVE COSTS

The ENA considers that operation of the LGNCs is likely to be administratively inefficient. The AEMC has correctly identified a number of costs associated with the rule change proposal:

- Costs of designing the LGNC;

- Cost to the AER of producing and reviewing a guideline or multiple guidelines applicable to different circumstances;
- Costs to stakeholders of engaging in associated consultation process;
- Costs to DNSPs of designing a methodology to estimate the direct benefit from distributed generation to distribution networks and translating it into negative network tariff.

» Costs of implementing and administering the framework, including:

- Transactions costs of creating an entirely new payment relationship in the NEM;
- Costs associated with setting up new systems and processes;
- Costs of collecting and managing information associated with the LGNCs;
- Cost of addressing or mitigating the risk of regulatory error in implementation of the framework.

With rapidly evolving technology and innovation, the ENA considers that the methodology and input assumptions for calculation the LGNCs would need to be reviewed on a regular basis. This means that the administrative burden on DNSPs is likely to be higher than just a simple adjustment as part of annual pricing proposals contemplated by the proponents. ENA encourages the AEMC to seek to quantify these process costs, with reference to comparable existing review processes in Australia and internationally.

RESPONSE TO THE AEMC ISSUES FOR CONSULTATION

ASSESSMENT FRAMEWORK

Question 1 Assessment framework

1. Would the proposed framework allow the Commission to appropriately assess whether the rule change request can meet the NEO?
2. What is the relevance, if any, of reliability and security for the purposes of assessing the proposed rule (or a more preferable rule)?
3. What changes, if any, to the proposed assessment framework do you consider appropriate?

The ENA supports the proposed assessment framework.

The regulatory rules have been designed to meet the *National Electricity Objective* of promoting efficient investment in, and use of, electricity services for the long-term interests of consumers of electricity with respect to price, quality, reliability, safety and supply. The AEMC has considered the regulatory framework for embedded generation in a number of rule changes flowing from the Power of Choice reforms.

The ENA agrees with the AEMC that the question that needs to be addressed in the first instance is whether there is an issue with the existing provisions of the NER. The ENA's submission describes a number of mechanisms in the NER that incentivise market participants to invest efficiently in and procure embedded generation.

Further, the ENA considers that the issues of reliability and security of supply are relevant to the assessment of the proponents' suggested solution, or any alternative. This is because embedded generation, depending on circumstances, can increase or reduce the need for network augmentation to ensure the reliability of electricity supply.

PERCEIVED ISSUE WITH CURRENT NER

Question 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?
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?
3. If your answer to questions 1 or 2 is 'no', what is the

specific area in which the current NER provisions do not achieve these outcomes – for example, is the issue with the current provisions only related to embedded generators of a certain type or below a certain size, or is there an issue for all embedded generators?

Based on the examination of the existing regulatory mechanisms for DNSPs under the current Chapters 5 and 6 of the NER, the ENA considers the existing regulatory framework provides a sufficiently comprehensive package of incentives for networks to adopt the most cost effective solution, including both network and non-network options. As such, the ENA considers that the current NER mechanisms contribute to the achievement of the NEO and foster efficient investment in, and use of, embedded generation.

The ENA, however, notes that these mechanisms are supplemented by a range of state-based regulatory arrangements, which are not uniform across jurisdictions in the National Electricity Market. Until the regulatory obstacles to efficient investment these present are addressed at a jurisdictional level, it is unlikely that standard level of efficient investment in embedded generation can be achieved.

DETERMINING AVOIDED COSTS

Question 3 Determining avoided costs

1. What are the factors that influence the long-run network costs that can be avoided through embedded generation? For example, do these cost savings depend on the location, voltage and type of generation?
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?

These issues are discussed in greater detail in the attached Frontier Economics report.

SPECIFICITY OF CALCULATIONS

Question 4 Specificity of calculations

If LGNCs of some form were to be introduced:

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?
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?

There is a trade-off between the accuracy of any LGNC and the simplicity of its calculation.

The AEMC correctly directs stakeholders' attention to the fact that if the calculation of the long-term avoided network costs is not sufficiently accurate, than the LGNCs are more likely to send inappropriate price signals to embedded generators, thereby encouraging inefficient investment decisions. If this is the case, the overall effect of the LGNCs is likely to increase networks total costs, leading to higher network charges for consumers. This outcome is contrary to the *National Electricity Objective*.

With rapidly evolving technology and innovation, the ENA considers that the methodology and input assumptions for calculation the LGNCs would need to be reviewed on a regular basis. This means that the administrative burden on DNSPs is likely to be higher than just a simple adjustment as part of annual pricing proposals contemplated by the proponents.

POTENTIAL BENEFITS OF THE PROPOSAL

Question 5 Potential benefits of the proposal

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?
    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?

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?

d. Reduce or increase the prices consumers pay for electricity?

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?

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

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

The value of embedded generation is time and location specific, e.g. it depends on the location of a constraint in the network. Therefore, for an LGNC to be effective it would need to vary by geographical location. The complexity of having more accurate pricing down to the individual customer levels is not likely to be possible given the level of uncertainty, nor is it likely to make sense in terms of the complexity of such arrangements and their associated implementation costs.

As a result, it is likely that any distribution credit will overcompensate and undercompensate specific customers (i.e. the value of the credit will be more or less than the net economic benefits created by that specific customers' embedded generation system). The ENA notes that the proposed rule suggests that the credit should not be negative, even if the cost of catering for bi-directional flows is deemed to exceed the benefits of the exported electricity to the network, which will further exaggerate this issue. Given this, cross-subsidisation in particular presents a risk.

POTENTIAL COSTS OF DESIGN, IMPLEMENTATION AND ADMINISTRATION

Question 6 Potential costs of design, implementation and administration

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? To what extent does this depend on:

   a. To whom LGNCs are applied (i.e. 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 (and, in turn, LGNCs) – i.e. whether separate calculations are made for different voltage levels and/or locations?

   c. How often the calculation is updated?

   d. How often the LGNCs need to be paid?

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)?

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

The ENA considers that operation of the LGNCs is likely to be administratively inefficient. The AEMC has correctly identified a number of costs associated with the rule change proposal. These are discussed on p.7.