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5 February 2016

Mr John Pierce
Chairman
Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

Dear Mr Pierce

ERC0191 - NATIONAL ELECTRICITY AMENDMENT (LOCAL GENERATION NETWORK CREDITS) RULE 2015 – CONSULTATION PAPER.

Ergon Energy Corporation Limited (Ergon Energy), in its capacity as a Distribution Network Service Provider in Queensland, welcomes the opportunity to provide comment to the Australian Energy Market Commission (AEMC) on its *National Electricity Amendment (Local Generation Network Credits) Rule 2015 – Consultation Paper* (Consultation Paper).

Ergon Energy's comments in relation to the specific issues in the Consultation Paper and our responses to the questions raised therein are included in the attached submission.

Should you require additional information or wish to discuss any aspect of this submission, please do not hesitate to contact either myself on (07) 3851 6416 or Trudy Fraser on (07) 3851 6787.

Yours sincerely

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Enc: Ergon Energy's submission

Submission on the *National Electricity Amendment (Local Generation Network Credits) Rule 2015 - Consultation Paper*

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Australian Energy Market Commission

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This submission, which is available for publication, is made by:

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Introduction

Ergon Energy Corporation Limited (Ergon Energy) welcomes the opportunity to provide comment to the Australian Energy Market Commission (AEMC) on its *National Electricity Amendment (Local Generation Network Credits) Rule 2015 - Consultation Paper* (Consultation Paper).This submission is provided by Ergon Energy, in its capacity as a Distribution Network Service Provider in Queensland.

As a member of the Energy Networks Association (ENA) the peak national body for Australia's energy networks, Ergon Energy has also contributed to and is fully supportive of the issues raised in the ENA's submission.

Ergon Energy is committed to changing the way our customers value us, from simply providing an essential service to a provider of essential infrastructure that connects and enables a market between buyers and sellers of both renewable and traditional energy sources. In line with this, we have strategically positioned our network as an open access platform for distributed renewable energy resources, efficiency, demand management and storage. Our strategic position as an 'open access platform' is supported by a number or key initiatives, which include, though are not limited to:

- Tripling solar access to the grid – we are supporting the 200 to 300 new solar energy system connections being made each week by leading the way with our innovative adaptation of STATCOM power electronics technology. This technology, which is used to absorb and/or export reactive power to assist in the control of network voltages, could potentially triple the number of customers that can connect solar to our urban networks, reducing fossil fuel needs and improving utilisation of our electrical networks.
- Demand management capability beyond expectations – over five-years we delivered 139MVA in demand reductions, the equivalent of removing a city the size of Rockhampton off the grid at peak time, significantly reducing the need to augment the network and supporting energy and materials conservation (and placing downward pressure on prices). Over the last 5 years customer consumption has dropped 15% taking the equivalent of 250,000 cars off the road.
- Reducing our reliance on diesel – in our isolated communities, we are aiming to reduce our reliance on diesel to zero by 2050, using solar, wind and geothermal generation investments. The success of our award winning Doomadgee solar farm led to ARENA funding approval for its expansion, which is aimed at cutting diesel use in the community by 33% and accelerating the renewable rollout in isolated communities across Australia. Our energy saving powersavvy program also works with residents to reduce diesel and associated greenhouse gas emissions. Stage 2 is subject to further approvals.

Ergon Energy's strategy is to create an effective market that is technology agnostic and therefore Ergon Energy does not support the proposal to introduce a local generation network credit (LGNC) payment, from distribution networks to embedded generators (EGs). Generation is often the most expensive and least reliable form of network support with other options such as tariffs, education, load control, efficiency and capacity being more efficient and effective with parallel benefits for customers and the economy. The proposed LGNC arrangements are not an appropriate mechanism for dealing with network constraints.

Specifically, the proposal seeks to make all EGs eligible for LGNCs irrespective of where they are located in the network. As a result, DNSPs such as Ergon Energy would be required to pay for generation in non-constrained areas of the network, despite there being no direct network benefit from that generation. Further, notwithstanding this issue, there is no guarantee that customers on a constrained feeder will respond in a way that addresses the constraint. Equally, the intermittency of generation means that, even if customers on a constrained feeder do respond, it cannot necessarily be relied upon to lower network peaks.

As noted by the AEMC in the Consultation Paper, there may be no benefits, and in fact other incremental costs for network businesses, associated with an increase in EG being built in non-constrained areas of the network.[1] Importantly, any such additional costs associated with upgrading the network to resolve, for example, power quality, harmonic or protection issues, will lead to higher network costs for all customers in the longer term. By way of example, the forecast cost of network upgrades triggered by the mass uptake of solar PV systems in Ergon Energy's distribution area in recent years, is approximately $44m (in $14-15 direct costs) out to 2020.

These issues are further compounded by the fact that DNSPs such as Ergon Energy are only funded to address known constraints within their current regulatory control period (5 year period); the proposed LGNC framework does not address those constraints. In fact in the current regulatory control period, Ergon Energy's forecast expenditure to address capacity constraints represents only 11% of our total capital expenditure, highlighting that there is only a limited number of constraints that need to be addressed in the period. It is also very rare where EG would be the lowest cost solution. Such a requirement from a constraints management perspective would result in compensation for customers who are not directly addressing the constraint for which funding was allocated, at the expense of all customers.

Additionally, on the basis that the proposal is predominately targeted at small-scale EGs, Ergon Energy considers it important to highlight that many of these small-scale EGs are also in receipt of generous jurisdictional feed-in tariff (FiT) payments (44c/kWh for excess generation out to 2028), which would continue to apply in addition to the LGNC. While it is acknowledged that retailer funder FiT payments are made on the basis of the 'energy value', as opposed to the 'network value' of the exports, many customers in Queensland remain on premium distributor funded FiTs, the costs[2] of which are passed through to all customers under jurisdictional scheme arrangements in Chapter 6 of the NER. As such, the payment of a LGNC to these customers would result in them effectively being paid twice for their generation, at a cost to all distribution customers, regardless of whether or not they have an EG installed at their premises.

In Ergon Energy's view the most appropriate way to address constraints on our network is through targeted offerings to the customers we want to incentivise on the basis of their ability to contribute to resolution of the constraint and to it being the lowest cost, technologically acceptable option. This could be through a variety of means including entry into demand management or network support contracts with customers (which may include incentive payments), working with retailers to offer products, or working with aggregators to deliver desired capacity. These mechanisms are currently available to DNSPs and do not require a change to the National Electricity Rules (NER). During the preceding financial year (2014-2015) Ergon Energy's Demand Management (DM) program delivered an aggregate capital deferral of over $664 million through the delivery of 139.6MVA of demand reductions through utilisation of such mechanisms. Specific examples of Ergon Energy's involvement in these initiatives have been included in our responses to the questions raised in the Consultation Paper.

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[1] Australian Energy Market Commission – Consultation Paper – *National Electricity Amendment (Local Generation Network Credits) Rule 2015*, p.5.

[2] Ergon Energy paid customers $115m in 2014-15. For 2015-16 regulated retail prices, the Queensland Competition Authority has indicated that that the Solar Bonus Scheme makes up 8% of the retail bill.

In addition to these initiatives, Ergon Energy considers that existing NER provisions are likely to provide appropriate price signals for efficient embedded generation, and 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. Our reasons for this are also detailed in our response to the questions raised in the Consultation Paper.

In consideration of these issues, Ergon Energy agrees with the, ENA that the AEMC should make a make a draft determination not to approve the rule. We also agree with the ENA, that should the AEMC consider further consideration of a more preferable rule it should aim to conduct an extended consultation schedule, including its foreshadowed process of preparation of a separate Options Paper.

Consultation Paper Feedback Question	Ergon Energy Comment
Question 1: Assessment framework	
1. Would the proposed framework allow the Commission to appropriately assess whether the rule change request can meet the National Electricity Objective (NEO)?	Ergon Energy agrees that the relevant impacts of the NEO against which the rule change should be assessed, are *both* price and reliability and security of supply. Specifically, an assessment in terms of price alone risks the LGNC incentivising behaviours which result in system security and reliability of supply issues, which drive investment in network infrastructure and an increase in costs to all customers, including those who do not have EG. In terms of price, Ergon Energy considers it essential that the assessment considers the true impact on both Capex and Opex, and therefore electricity prices, in both the immediate and long term. Furthermore, consideration must also be given to the costs associated with the network impacts created by excess generation. In our 2015 Regulatory Proposal, Ergon Energy highlighted the correlation between accommodating embedded generation and an increase in network costs and therefore electricity prices. Specifically, we estimated the costs of enabling the connection of small-scale EGs to our network to be in the order of $41m Capex and $12m Opex (excluding overheads in $2014-15) for the regulatory control period 2015-2020. However, notwithstanding the above issues, Ergon Energy agrees with the ENA in supporting the AEMC's position that 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.

2. What is the relevance, if any, of reliability and security for the purposes of assessing the proposed rule (or a more preferable rule)?	In Ergon Energy's Final Regulatory Determination by the Australian Energy Regulator (AER) for the regulatory control period 2015-2020, expenditure to address capacity constraints only accounts for 11% or $308.5m of total capital expenditure (excluding overheads in $2014-15). As evidenced by this figure, there are currently only a limited number of constraints on our network that need to be addressed in the current regulatory control period. However, while there may be sufficient capacity in many areas of the network in the immediate term to accommodate increased generation without adverse consequence, Ergon Energy is concerned that in the longer term, as networks are designed to a lower capacity in response to reduced demand and increased availability of generation and energy storage, the lack of firmness, controllability or guarantee that generation will operate during a peak will mean that: (a) networks will require increased redundancy (i.e. a 1kVA of LGNC generation will not equate to a 1kVA reduction in network capacity required due to lower confidence); and (b) where generation fails to offset peak demand, resulting in either capacity ratings of the network being exceeded or voltage moving outside statutory limits, the network will fail, resulting in outages and/or plant damage. For this reason, Ergon Energy considers it imperative that reliability and security of supply be considered in the AEMC's assessment of the proposed rule.
3. What changes, if any, to the proposed assessment framework do you consider appropriate?	Ergon Energy recommends that the proposed assessment framework should be expanded to include: • Consideration of other forms of demand side participation. Specifically, any technology that reduces network costs would have an overall benefit to the energy market. For EG to be incentivised through the proposed LGNC arrangements, it would need to be superior to any other demand side solution capable of delivering the same benefit. For example a load reduction initiative may be more cost competitive and offer the same network benefit and where this is the case, should therefore take precedence over the incentivising of a higher cost and less efficient EG solution • Whether EG can be considered truly firm for DNSP planning and design purposes.

	Ergon Energy notes that due to the intermittency of generation, even if customers on a constrained feeder do respond, it cannot be relied upon to lower network peaks. In fact in Ergon Energy's experience, when caused by environmental conditions such as sudden changes in the weather, this intermittency can exacerbate network constraints through the creation of new demand peaks. For example, storm clouds rolling across the sky in the middle of the afternoon, significantly and suddenly reduce the output from PV systems, but air-conditioning load continues as the high temperature and humidity remain. This sudden loss of PV output must be responded to with a correspondingly quick increase in grid-supplied electricity, creating a spike in demand on the grid that can even exceed normal evening peaks. This phenomenon is well illustrated in the load profile from the Dundowran Feeder in the Hervey Bay region of Ergon Energy's network, which is included at Appendix 1 to this submission. • Any additional costs that may occur from increased EG. Specifically, increased generation in areas of the network that are not designed to accommodate that generation will likely result in system security and reliability of supply issues, which drive investment in network infrastructure and increased costs for all customers, including those who do not have EG. Furthermore, Ergon Energy suggests that, given the rapid evolution of bi-directional energy flows, more detailed consideration be given to the ongoing appropriateness of rule 6.1.4(a) of the NER. Specifically, rule 6.1.4 currently prohibits DNSPs from charging distribution use of system charges for the export of electricity into the network. The electricity market has changed significantly since this rule was established and Ergon Energy does not believe it has been properly tested against the NEO in recent times.
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	Yes. Ergon Energy considers that current and impending NER provisions provide appropriate incentives in this regard. Specifically:

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?	**Cost-reflective distribution network tariffs**. Ergon Energy agrees with the ENA that a cost-reflective EG tariff can already be proposed and determined as part of Tariff Structure Statement and annual pricing proposal rather than being prescribed by a separate rule change **Avoided Transmission Use of System (TUoS) charges** DNSPs are required to make payments to EGs in recognition of the cost that would have been payable by the DNSP to the transmission network service provider had an (eligible) EG not been connected to the network. Although avoided TUoS is most often paid to eligible large scale generators, it is important to note that this payment can also extend to small EGs where the applicant is eligible, and seeks to negotiate their connection under Chapter 5 of the NER. In the preceding financial year (2014-15) Ergon Energy paid $1.88m in avoided TUoS charges. **Network support payments** Within the existing regulatory framework, DNSPs such as Ergon Energy are able to negotiate network support payments with EGs, for the provision of generation to support network operation and defer capital investment. As part of its broader demand management initiatives, Ergon Energy currently has five agreements in place to deliver network support in areas of network constraint. In the preceding financial year (2014-15), Ergon Energy paid $2.58m for a total of 34MVA of network support, in accordance with the terms of these agreements. Importantly, the decision to make such payments is informed by the outcome of a cost benefit analysis that is performed in consideration of a range of options to address the identified issue. **Small generation aggregator framework** This framework facilitates small embedded generator participation in the market by enabling aggregation and sale of their output through a third party, Market Small Generator Aggregator. Under this framework more parties are able to offer non-network solutions, thereby providing DNSPs' access to a broader range of options and the ability to procure those options where it is efficient to do so.

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?	Yes. Ergon Energy considers that current and impending NER provisions 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. Specifically: **Distribution network planning and expansion framework** DNSPs such as Ergon Energy have obligations under Chapter 5 of the NER to undertake a Regulatory Investment Test (RIT-D) where the most expensive credible option to address an identified need (i.e. a constraint) is more than $5m. In undertaking the RIT-D, Ergon Energy is required to screen for non-network alternatives, which can include EG. Since commencement of the RIT-D in 2013, Ergon Energy has undertaken two assessments under the RIT-D framework. In both cases, Ergon Energy received one submission from a generation proponent. However, despite this, in both cases it was determined (in accordance with the RIT-D process) that the generation solution was not preferred on the basis of there being a more prudent and efficient option available. Although a generation solution was not preferred in these cases, the RIT-D clearly obliges DNSPS to actively consider non-network solutions, including EG as part of any significant investment decisions. **Demand Management Incentive Scheme (DMIS)** This recently revised mechanism encourages DNSPs to trial innovative non-network options that benefit customers through reduced costs over time. While the revised DMIS is not expected to be finalised until 1 December 2016, Ergon Energy has continued to deliver a broad range of demand management initiatives as part of its ongoing Demand Management Program. Ergon Energy's demand management activities are funded via several mechanisms, including the existing *Demand Management Innovation Allowance*, in accordance with the demand management objectives and included within our Final Distribution Determination. In the preceding financial year, Ergon Energy successfully delivered 54.6MVA of demand reduction, equating to a total of $530m in capital deferral. In addition to these prescribed mechanisms, Ergon Energy has implemented a number of other proactive measures in this regard. A prime example of this is the publication of a Demand Response Incentive Map (DRIM), as a market communication tool for engaging the

	market to identify the value, location and metrics related to our demand management program of works. The DRIM, which is currently in use in a specified area of Ergon Energy's network identifies the exact location and timing of a constraint, and defines the customer base eligible to access available incentives. Ergon Energy is currently developing the capability to expand and publish the DRIM map across Queensland, in the form of a Network Capacity Incentive Map, to highlight all of the network areas under constraint or at risk, to provide better market information and incentivise non-network solutions to achieve efficient investment in, and operation of, the electricity system in a way that minimises long-term costs. Ergon Energy has voluntarily undertaken these initiatives on the basis of the associated benefits to both our network and our customers. As such, we consider that where such mechanisms are available to deliver these types of outcomes, they should continue to be available on a non-mandated basis for implementation where considered both prudent and efficient by a particular network service provider. **Capital Expenditure Sharing Scheme and the Efficiency Benefit Sharing Scheme** As noted by the AEMC in the Consultation Paper, these Schemes provide DNSPs such as Ergon Energy with incentives to invest in and operate their networks efficiently by allowing them to retain a portion of any associated cost savings. Ergon Energy agrees with the AEMC that this effectively incentivises a DNSP to substitute a non-network solution, such as EG, for a previously anticipated investment in the network, where the former represents a more efficient investment decision.
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?	N/A

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?	The ability for generation to avoid long-run network costs is dependent on its location in the network, the time at which it generates (i.e. ability to reduce peak in constrained areas) and how reliable it is (i.e. whether it can reasonably be relied upon to the level of security of supply criteria necessary to achieve legislated reliability targets). It is important to note that the Consultation Paper has focussed on capacity constraints, which in Ergon Energy's Final Regulatory Determination for the regulatory control period 2015-2020, only account for 11% or $308.5m of total capital expenditure. As demonstrated by this forecast, Ergon Energy is only expecting a limited number of constraints that need to be addressed in the current regulatory control period. Ergon Energy is concerned that the proposed LGNC arrangements will not assist to address these constraints as there is no guarantee that there will be sufficient generation capacity available on a particular constrained feeder to address the constraint, or that customers on the constrained feeder will respond in a way that actually addresses the constraint. Furthermore as noted in response to Question 1(3), the intermittency of generation means that, even if customers on a constrained feeder do respond, it cannot be relied upon as a consistent mechanism to lower peaks. As a consequence, DNSPs such as Ergon Energy and its customers would receive no benefit where a LGNC is paid to a customer who installs technology that does not address a specific constraint for which the DNSP is funded through a revenue cap. This would result in compensation for customers who are not directly addressing the constraint for which the funding was allocated. In addition to the abovementioned forecast to address capacity constraints on the network, the AER also approved the following network expenditure by Ergon Energy for the current regulatory control period, in relation to which embedded generation will have limited or no positive impact: • Voltage constraints – 4% or $119.8m (excluding overheads in $2014-15) (note voltage constraints are highly locational, particularly within the distribution network to the point of a particular spur or section of line). Also included is $41m of Capex and

	$12m of Opex (excluding overheads in $2014-15) specifically for responding to overvoltage issues in the LV network as a result of micro EG units (namely Solar photovoltaic (PV)) which have caused the voltage to go outside statutory limits due to poor correlation with demand. • Refurbishments – 27.5% or $786.6m (excluding overheads in $2014-15) • Opex – $1732.4m (excluding overheads in $2014-15) Furthermore, of Ergon Energy's total expenditure for the regulatory control period 2015-2020, only 54 projects and $191.8m (excluding overheads in $2014-15) relate to the sub-transmission network, with a total of 753 projects $274.4.9m (excluding overheads in $2014-15) relating to distribution or LV networks, meaning that investment is very much concentrated at the edges of the grid, and so the ability for EG to add any cost saving value will be highly determinate on location and voltage level, with aggregation limited also. For these reasons Ergon Energy considers that local support agreements or localised demand management programs, which encompass EG, publicised through a DNSP's Distribution Annual Planning Report (DAPR), or initiatives such as Ergon Energy's Demand Response Incentive and Network Capacity Incentive Map will provide best value for both EGs and DNSPS, and therefore all customers.
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?	Ergon Energy notes that any expenditure benefits associated with EG are generally savings in Capex as a consequence of avoided or deferred augmentation. We also note that EG in fact impacts our maintenance numbers negatively on the basis that reduced utilisation has no direct correlation with required maintenance programs and therefore costs. Notwithstanding, we have in the past considered some marginal Opex benefit should EG facilitate the removal of infrastructure, for example in the case of removal of a Single Wire Earth Return (SWER) line where customers are 100% reliant on EG. However, even in that situation, the annual avoided preventative maintenance cost would be approximately $100/km, which is minimal.

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?	As stated previously in this submission, Ergon Energy does not support the introduction of LGNCs. Rather we consider that local network support agreements, and mechanism such as a local optimal incremental pricing (OIP) scheme (which is part of broader DM offering and utilises a demand risk valuation methodology to enable network businesses to value demand side solutions based on local area network conditions, growth rates and customer demographics) would be most efficient in providing long range price signals, be sufficiently localised, and more adequately address local investment needs to achieve the lowest cost solution. This in turn will place downward pressure on electricity prices. As highlighted in Box 5.1 – 'Illustration of the trade-off between accuracy and simplicity' of the Consultation Paper, the LGNC will result in a less optimal outcome as it will smear the value across an undesirably large area resulting in lack of sufficient uptake in constrained areas, which are highly localised, and EG proponents that are appropriately located (and able to export to the network) being unfairly undercompensated in comparison to an EG that is poorly located. Ergon Energy would also like to highlight that the term "local" is not consistent across the National Electricity Market (NEM). We further highlight that Ergon Energy's distribution area covers approximately 50% of the NEM geographical area, and includes three distribution pricing zones, and three transmission pricing zones. This in itself will result in any LGNC being highly complex to develop. This complexity (even for a smeared LGNC like existing load tariffs) is likely to deter EG confidence and/or acceptance due to their inability to readily comprehend any benefits under the arrangements. Ergon Energy therefore considers that an OIP or local network support agreements are significantly less complicated (for the DNSP but also for the proponent to understand) and will deliver an outcome that is more beneficial to the broader customer base by deferring augmentation in the most efficient and cost effective means possible.

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?	Although Ergon Energy does not support the introduction of a LGNC, if some form of LGNC were to be introduced, we consider the calculation should be updated annually in line with other tariff reviews, and the release of a DNSP's DAPR. Additionally, while Ergon Energy would not encourage additional reporting, if the LGNC were to be introduced, it should be open to regular review in terms of the operational cost, value delivered, and net impact to all customers, in order to determine its ongoing viability.
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?	Due to the inherent complexity, and therefore likely unsuitability of DNSPs performing different LGNC calculations for different voltage levels and/or geographic locations, Ergon Energy considers that compared with the current NER provisions, the proposal would deliver inferior price signals to EGs. This would be due to a lack of locational and time based elements to encourage EG at the right place, the right time, and in the right volume. Furthermore, any smearing of the LGNC will also mean that the value will likely be 0c. As noted earlier in this submission, Ergon Energy considers there are existing mechanisms available to DNSPs to appropriately incentivise EGs. Specifically, Ergon Energy considers that local support agreements or localised demand management programs, which encompass EG, publicised through a DNSP's DAPR or initiatives such as Ergon Energy's Demand Response Incentive and Network Capacity Incentive Map will provide best value for both EGs and DNSPs. These mechanisms would actually result in downward pressure on electricity prices, as opposed to likely upward pressure by the introduction of a LGNC, even in its most efficient form.
(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?	As stated in response to Question 2(2) above, Ergon Energy considers there are sufficient incentives in the existing regulatory framework for DNSPs to adopt efficient network and non-network solutions. On this basis, we do not consider that the proposal to introduce a LGNC will result in superior incentives and may in fact result in inferior incentives. Specifically, where a DNSP such as Ergon Energy is obliged to pay a LGNC, the use of EG may be preferred to another more efficient non-network alternative, in terms of cost. That is, where an alternative to EG is available and can deliver the same benefits at a lower cost,

	existing obligations to pay an EG a LGNC will more often than not see the EG utilised as the final option when the overall costs (i.e. of both the LGNC and the adoption of any alternate solution) are considered. The net result of this is that the costs to network service providers, and ultimately their customers will be unnecessarily increased.
(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?	Most definitely. DNSPs such as Ergon Energy are subject to stringent reliability and security of supply requirements, which are unable to be contracted to a third party. Consequently where, under a LGNC framework, a DNSP relies on EG as a mechanism to assist with meeting these requirements, any risk associated with this remains with the DNSP. As such a failure of the EG portfolio, will result in the DNSP failing to meet its reliability and security of supply requirements and subject the DNSP to relevant penalties. Ultimately this will require DNSPs to discount the use of EG (i.e. by a confidence factor) which would require ongoing network investment, and likely result in either an LGNC value of 0c (which would still have a cost to calculate and administer) or a LGNC being paid far beyond the value it delivers.
(d) Reduce or increase the prices consumers pay for electricity?	Ergon Energy considers that the proposal will in fact lead to an increase in prices both in the short and longer term. Under the proposal DNSPs such as Ergon Energy would be required to pay for generation in non-constrained areas of the network, despite there being no direct network benefit from that generation. Further, notwithstanding this issue, there is no guarantee that customers on a constrained feeder will respond in a way that addresses the constraint. Equally, the intermittency of generation means that, even if customers on a constrained feeder do respond, it cannot necessarily be relied upon to lower network peaks and therefore contribute to the avoidance or deferral of network augmentation. Additionally, Ergon Energy notes that in accordance with Chapter 5A of the NER, a DNSP must in developing its connection policy, comply with the AER's Connection Charge Guidelines (Guidelines) for Electricity Retail Customers. This includes the requirement in clause 1.1.1 of the Guidelines for a DNSP's connection policy to include a threshold or thresholds (referred to as the shared network augmentation charge threshold (SNACT)) below which retail customers (other than non-registered EGs and real estate developers) will not be required to make a capital contribution towards the cost of the augmentation

	(insofar as it involves more than an extension). Although, by virtue of clause 7.1.1 of the Guidelines, non-registered EGs are not eligible for the exemption from being charged for augmentation under subparagraph 5A.E.1 (b)(2) of the NER, there is no such limit on eligibility stated for micro EG customers. Consequently, as retail customers, micro EG customers (who would also be eligible for a LGNC under the proposed changes to the NER) are also eligible for the exemption from being charged for augmentation under subparagraph 5A.E.1 (b)(2) of the NER. In terms of Ergon Energy's current connection policy, this means that small-scale EG customers are not required to contribute to the cost of any shared asset augmentation necessary to enable their connection, where their application is under the prescribed SNACT (80amperes or 10kVA on a single wire earth return network). Furthermore, in accordance with rule 6.1.4(a) of the NER, EGs also don't pay any local use of system charges either for exporting energy into the network. The combined effect of these issues is that the majority of small-scale EG customers pay little to nothing upfront to connect their EG to the network, even though the cost to the DNSP (and therefore all customers) in Ergon Energy's case is estimated to be in the order of $41m Capex and $12m Opex (excluding overheads in $2014-15) for the regulatory control period 2015-2020. Ergon Energy notes that many of these customers are also in receipt of generous jurisdictional feed-in tariff (FiT) payments. While it is acknowledged that retailer funder FiT payments are made on the basis of the energy value of the exports, many customers in Queensland remain on premium distributor funded FiTs, the costs of which are passed through to all customers under the jurisdictional scheme provisions in Chapter 6 of the NER. As such, the payment of a LGNC to these customers would result in them effectively being paid twice for their generation, at a cost to all distribution customers, regardless of whether or those customers have an EG installed at their premises.
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	Ergon Energy's responses to the preceding questions are provided on the assumption that the LGNC is administered as described by the proponents and the AEMC. That is, on the basis that the LGNC is not perfectly locational or targeting availability, and therefore involves some element of smearing.

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?	As above. However, notwithstanding the more simplistic nature of a smeared approach, Ergon Energy has also been cognisant of the costs to administer the framework, despite a LGNC value of $0 in some cases.
(c) The proportion of the estimated avoided network costs that are reflected in the LGNCs paid to embedded generators?	Although Ergon Energy's responses to the questions have not specifically considered the proportionality of costs that would be included in the LGNC, we note that the costs would need to be limited to capacity related Capex. As evidenced by our response to Question 3(1), any remaining costs would have no direct correlation to LGNC, and their inclusion in the LGNC would put increased pressure on electricity prices.
3. If you do not consider that the proposed rule would enhance the NEO, are there potential alternative approaches that may do so?	As stated earlier in this submission, Ergon Energy does not support the introduction of LGNCs. Rather we consider that local network support agreements, and a local OIP scheme (which is part of broader DM offering), both of which do not require a change to the NER, would be most efficient in providing long range price signals, be sufficiently localised, and more adequately address local investment needs to achieve the lowest cost solution. This in turn will place downward pressure on electricity prices.
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	Ergon Energy considers the proposed LGNC arrangements would be complex to administer and impose significant additional costs on DNSPs and other stakeholders. Specifically, there would be costs associated with both designing the LGNC and implementing and administering the framework. These costs would include, though not necessarily be limited to: • The costs to DNSPs of designing aa methodology to estimate any benefit

is applied to all embedded generators or whether there are criteria based on a generator's capacity, availability and/or location)?	associated with the EG and translating that into a negative network tariff • the costs to update billing systems to enable payment of the LGNCs • the general costs of administering the framework, i.e. the collection and management of information applicable to the operation of the framework. Furthermore, we consider that the magnitude of these changes would be most significant, where different LGNC calculations are required for different voltage levels and/or geographic locations.
(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?	As intimated above, more detailed and complex calculations based on voltage and locational characteristics would likely require more complex and costly changes to both systems and process. Furthermore, more complex arrangements would likely necessitate increased customer engagement to facilitate the required understanding of the LGNC framework, which would also come at an additional cost to network businesses such as Ergon Energy.
(c) How often the calculation is updated?	Ergon Energy agrees with the ENA that the methodology and input assumptions for calculation of the LGNC would need to be reviewed and updated on a regular basis to sufficiently take account of rapidly evolving technology and innovation within the market. The extent of any changes to systems and process as a consequence of these updates will necessarily depend on the outcomes of the review and will therefore vary accordingly.
(d) How often the LGNCs need to be paid?	The required frequency for LGNC payments would be a consideration in any billing system and process changes to support the arrangements. However due to the transactional costs associated with processing payments, more frequent payments will mean higher costs to network business, and ultimately their customers.
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)?	Ergon Energy has not been able to quantify the likely costs associated with the abovementioned changes. However, we note that these are not likely to be insignificant. Furthermore, as stated in our responses to (a)-(d) above, the greater the specificity and therefore complexity of the LGNC calculation and associated payment obligations, the greater the costs to network businesses and their customers.

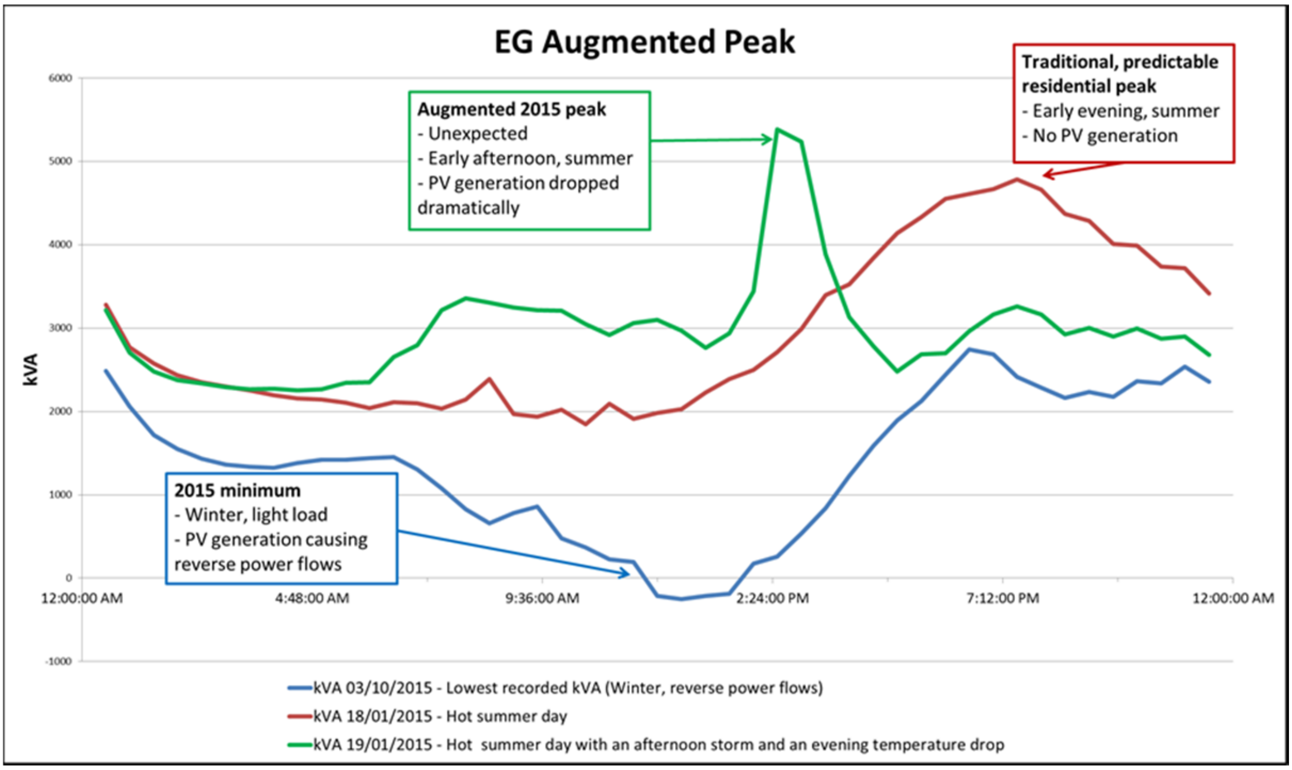
3. How do these costs compare to the expected benefits of the proposed rule change?	See above comment. As Ergon Energy has not been able to quantify the likely costs associated with the abovementioned changes, we are unable to draw an accurate comparison between such costs and any expected benefits of the proposed rule change, which would be equally difficult to accurately quantify with any degree of accuracy in consideration of applicable locational characteristics etc.
Further Comment **Topic**	
Lack of discussion on controllability of EG by DNSP	Ergon Energy considers that where a DNSP is required to pay a LGNC to an EG, sufficient control over that generation should be provided to the DNSP by the EG to ensure that the forecast benefits for which the EG is being rewarded are able to be realised by the DNSP. This would be similar to the existing treatment of loads under control whereby a customer can opt-in to give control of appliances on a dedicated circuit to the DNSP and in return receives a reduction in the electricity price paid. Ergon Energy considers this would deliver a far more equitable outcome for each of the parties involved.
Lack of diversity in EG	Approximately 25% of Queensland premises currently have Solar PV, which lack diversity within a geographical area (both in terms of generation time but also susceptibility to intermittency caused by weather events). Ergon Energy has attached at Appendix 1 to this submission, a case study example of the susceptibility of EGs to intermittency caused by weather events). While DNSPs are agnostic to the fuel source of an EG, Ergon Energy considers that by having the ability to impose conditions relating to the time, capacity and location of the required export, DNSPs can ensure that any payments made to EGs in respect of network support or benefits are both prudent and efficient.

Feeder Peaking

Feeder peaking occurs when solar PV generation is reduced (e.g. due to a sudden change in weather conditions), such that the load ordinarily supplied by the solar PVs at premises connected to that feeder, is suddenly required from the network. This results in a new unexpected peak on the feeder, causing it to become overloaded.

Ergon Energy's network planners have identified an evolving phenomenon in the load profiles of many of our distribution feeders in the middle of some summery afternoons. It appears that in areas of high solar PV penetration, an increasing proportion of electricity demand during the day is being met with PV generation. However, this generation is doing little to reduce the peak, or even creating new network risks due to the intermittency of generation caused by cloud cover. For example, storm clouds rolling across the sky in the middle of the afternoon, significantly and suddenly reduce the output from PV systems, but the air conditioning load continues as the high temperature and humidity remain. The sudden loss in PV output must be responded to with a correspondingly quick increase in grid-supplied electricity, creating a spike in demand on the grid that can even exceed evening peaks.

The Figure below is an example of 'feeder peaking' on the Dundowran feeder and is useful for demonstrating that while solar PV generation patterns may generally correlate with normal day time peaks, given the intermittency of solar PV generation, it is not a reliable source for demand deferral or as an alternative to augmentation.



Further, it is important to note that customers with PV generally have more appliances operating and therefore use more total energy. As the graph below illustrates, during the past year the fall in the amount of electricity being used by the average household without solar energy systems across regional Queensland has stabilised. At the same time, the electricity being used by households with solar has continued to increase on average. This behaviour is contributing to the augmented peak effect demonstrated above.

FALL HOUSEHOLD ELECTRICITY STABILISED