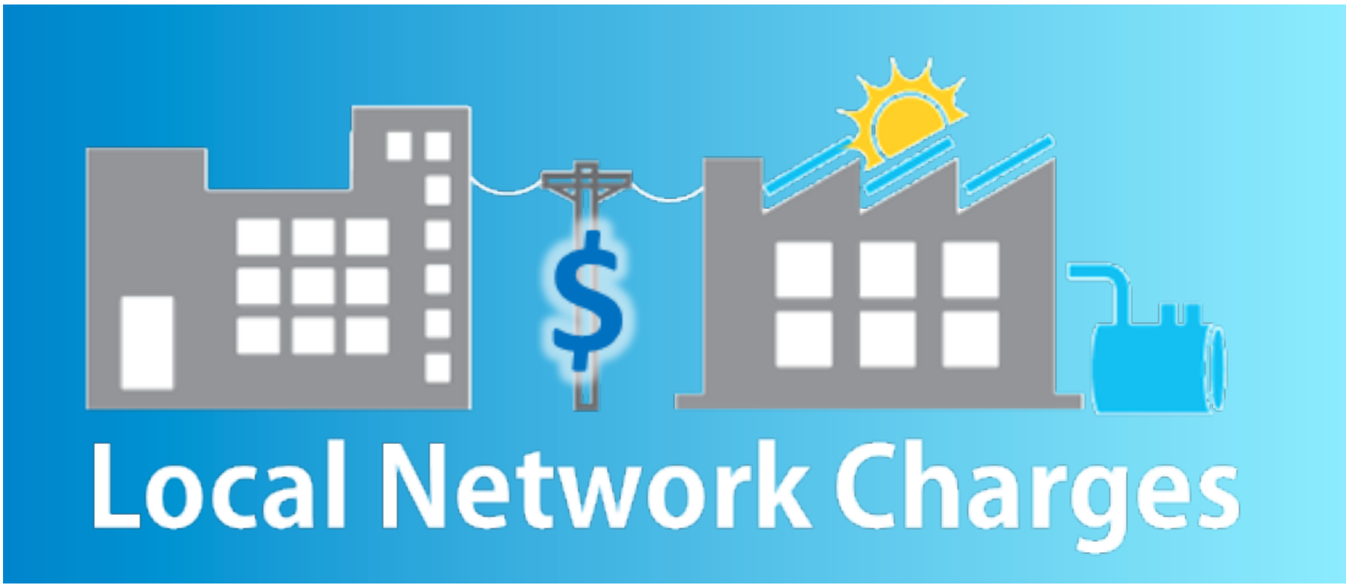

UTS: INSTITUTE FOR SUSTAINABLE FUTURES

METHODOLOGY FOR CALCULATING A LOCAL NETWORK CREDIT

Final Report

August 2016

2016

ABOUT THE AUTHORS

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

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While we acknowledge the great contribution made to this research by our partners, the analysis and conclusions in this report are the responsibility of the authors alone.

DISCLAIMER

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LIST OF ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIC	Average Incremental Cost
AFSL	Australian Financial Services License
ARENA	Australian Renewable Energy Agency
CAPEX	Capital Expenditure
CNRP	Cost Reflective Network Pricing
DG	Distribution Generation
DLF	Distribution Loss Factor
DNSP	Distribution Network Service Provider
FCAS	Frequency Control and Network Control Ancillary Services
HV	High Voltage
ISF	Institute for Sustainable Futures
kW	Kilowatt: a unit of power (real)
kWh	Kilowatt hour: a unit of energy
kVA	Kilovolt amp: a unity of power (apparent)
LET	Local Electricity Trading.
LG	Local Generation
LGC	Large-scale Generation Certificate.
LGNC / LNC	Local Generation Network Credit / Local Network Credit
LRMC	Long run marginal cost
LV	Low Voltage
MLF	Marginal Loss Factor
NCAS	Network Control Ancillary Services
NEM	National Electricity Market

NEO	National Electricity Objective
NER	National Electricity Rules
NPV	Net Present Value
OPEX	Operational Expenditure
PPA	Power Purchase Agreement. An agreement between an electricity generator and an electricity user, usually involving the user located at the same physical site as the generator.
PV	Photovoltaic
RET	Renewable Energy Target The federal Government renewable energy target, tracked via LGCs and STCs to
REPEX	Replacement Expenditure
RIN	Regulatory Information Notices
STC	Small-scale Technology Certificate. A renewable energy certificate representing 1 MWh of generation from a small scale renewable generator smaller than 100kW (see LGC above).
TEC	Total Environment Centre
TNSP	Transmission Network Service Provider
TOU	Time of use
TUOS	Transmission Use Of System
UK CDCM	United Kingdom Common Distribution Charging Methodology
UTS	University of Technology Sydney
VEET	Victorian Energy Efficiency Target
VNM	Virtual Net Metering An alternative name for Local Electricity Trading (LET)

EXECUTIVE SUMMARY

Context

This report sets out a recommended methodology for calculating a Local Network Credit (LNC) and summarises how the methodology was developed.

The work forms part of the Facilitating Local Network Charges and Virtual Net Metering research project, led by the Institute for Sustainable Futures (ISF) and funded by the Australian Renewable Energy Agency (ARENA) and other partners. The project is investigating two measures aimed at providing a level playing field for local energy, local network charges for partial use of the electricity network, and Local Electricity Trading (LET) (previously referred to as Virtual Net Metering or VNM) between associated local generators and customers. Local network charges are tariffs for electricity generation used within a defined local network area, and an LNC is a means to deliver such a partial charge via a credit paid to the generator.

Internationally, a number of jurisdictions have implemented a credit to local generators[1]. The USA and UK are the main examples, and methods range from a simple 'rule of thumb', such as in Connecticut, to rigorous 'before-and-after' modelling in Minnesota. Closer to home, network businesses such as ActewAGL and Ausnet are offering tariffs with similarities to an LNC, although the calculation methodology is unclear.

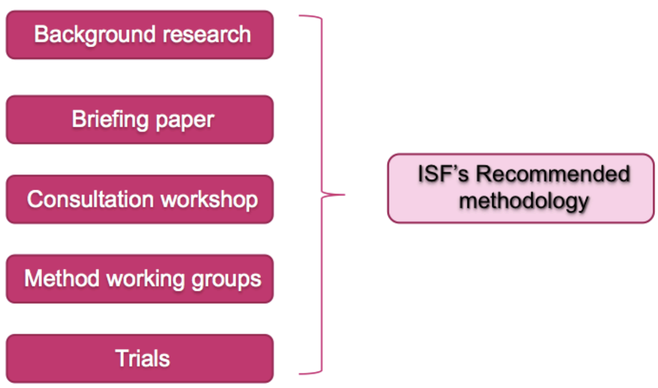
In July 2015, the City of Sydney, Total Environment Centre (TEC) and the Property Council of Australia, submitted a rule change request to the Australian Energy Market Commission (AEMC) for a Local Generation Network Credit.

The ISF project has conducted methodological development for an LNC and five virtual trials of the methodology in four Australian electricity networks. The trials and their outcomes are described in a separate report (Rutovitz et al. 2016).

The proposed LNC method recognises that only part of the network is used by local generators, and aims to both incentivise and recompense the benefits that flow to the network from generation that contributes to peak abatement.

Methodology development and principles

We first examined international precedents and produced a detailed briefing paper on methodology options. We proposed a number of principles: technology neutrality, cost reflectiveness, transparency, and practicality, and used these to consider alternatives at each step. The options paper was discussed at a methodology workshop attended by cross industry stakeholders, and over several sittings of a methodology working group established to discuss issues which could not be resolved on the day.



The methodology working group included a smaller team of network, generation and industry stakeholder representative that worked through the issues surrounding availability incentives, transmission inclusions, local generation costs and other more challenging parts of the methodology.

[1] Also called embedded or distributed generators

The main methodology components were identified as value calculation and tariff creation.

Following the workshop it was decided to use Long Run Marginal Cost (LRMC) as used for tariff setting as the primary input to value calculation, and to take two methods of tariff creation into the virtual trials, a pure volumetric method and a combined volumetric and capacity method. We further decided to commission work on the value creation calculation from Energeia as there was some concern that current LRMC values would not reflect the long run benefits of local generation.

Results of the virtual trials

Network LRMCs were the biggest influence on the total LNC value available. Ergon Energy's network had the highest cost and consequently the highest LNC, while Powercor's was the lowest. The other significant influence on the calculated LNC rate is the number of hours chosen for peak periods, as a broad band (i.e. many hours) results in a lower value. Peak LNC values ranged from:

- 6.8c/kWh in the Essential network based on offering for 1,300 hours in the year
- 32.5c/kWh in the Ergon network based on offering for 650 hours in the year.

The Essential network had the broadest payment times and therefore the least targeted LNC, which potentially incentivises generation outside of the times that it is necessary for peak abatement.

In all cases, the maximum LNC that a fully available (always on) generator connected at the LV level could capture fell between approximately one third and a little over one half of the tariff that is charged to an equivalent constant load. This stems from the fact that some of the network will always be used by a generator and is therefore not credited.

Recommended methodology

We recommend an LNC with the following features:

- A total value based on the Long Run Marginal Cost (LRMC) of the network levels above the connection point, and distinguished by customer class. The LRMC calculation methodology should match the DNSP's LRMCs used in existing consumption tariff setting (generally includes augmentation expenditure only) and be adjusted for power factor and for the capacity effects of avoided losses. Transmission network value should be included, but avoided *energy* losses excluded.
- The LRMC value should be scaled back by a benefit-sharing factor, to allow some of the benefits of reduced network costs to flow to the network and consequently other consumers via reduced charges.
- A tariff structure based on targeted volumetric payments with honed peak / shoulder / off-peak periods with approx. We suggest 500 hours or less in the defined peak window with at least a 90% peaking probability during that time would be an appropriate starting point, but should be refined by DNSPs based on the response of generators to the price signal.
- LG costs should be minimised in the short term through the same means as currently occurs, by the prevention of export when this imposes particular costs on the network. This will inherently prevent payment of an LNC when export is causing costs rather than benefits.
- In the long run we recommend that:

    - The cost of bi-directional networks flows should be included in LRMC calculations for tariff setting, and those identified costs subtracted from the LNC calculation;
    - The benefits of reduced replacement investment (repex) from downsizing should be included in LNC calculations; and
    - The cost of new connections should remain excluded from the LRMC (e.g. the line extension to a new property), however the costs of non-direct augmentation, repex and opex on the shared network driven by the new connections should be included (e.g. substation or line upgrades to deal with this new load).
- Informed by the economic modelling performed as part of this project (Kelly et al., 2016) it is also recommended that LNCs should not be paid to existing non-dispatchable generators, or to new generators under 10kW. This recommendation aims to maximise economic benefits to all consumers, on the basis that the primary value of LNCs is to influence the initial investment and/or operational decisions of generators in a way that supports the network. These generator categories were considered less able to fulfill these criteria. More work is required to determine the value of offering LNCs to existing dispatchable generators, depending on the network and generator circumstances.

The calculation method is also available in an accompanying spreadsheet [ISF LNC Calculator.xlsm].

Summary of recommendations

Value calculation

Framework for network value of LG

- **1)** Use LRMC as the value basis for the LNC.
- **2)** Use the same method to calculate LRMC as is used by networks in tariff setting.
  - **2.1)** Include repex value from downsizing or retirement as this becomes better understood.
- **3)** Apply a discounting and benefit sharing factor to the LRMC.

Calculation by location, network level and customer class

- **4)** Locational specificity to match specificity used by networks in consumption tariffs. Use customer class and voltage level as locational proxies for the type of network.
- **5)** Adjust LRMC for the network value of losses and network power factor impacts.

Transmission value

- **7)** Include Transmission LRMC value, signal value through probabilistic tariff structure as per recommendation 6).

Avoided losses

- **8)** Do not include the value of avoided losses, these are included in the energy value.

LG Costs

- **9)** Apply the interim solution of an export gateway.
- As bi-directional augmentation costs become more commonly quantified, subtract these from the LRMC value.

Tariff Creation

Volumetric allocation:

- **6)** Assess the probability of the peak happening in each hour of the year, allocate hours into peak, shoulder, off-peak (and optionally critical peak) periods.
- Choose relatively tight peak periods with high peaking probability.
- Multiply the value set in the previous steps by the peaking probability of each hour in the relevant period.

Generator inclusions and exclusions

- **10)** Exclude existing non-dispatchable generators, and new generators under 10kW from LNC payments (to maximise economic benefits).

Payment settlement

- **11)** The LNC should be mediated via a retailer; generators without a retailer should secure that relationship.

Conclusion

This work provides a recommendation for an LNC methodology, which is generally in line with the consumption tariff setting methodology. The inputs required for the LNC methodology are the same, or very similar, to those required for setting consumption tariffs, so the introduction of an LNC should not require undue administrative resources for calculation.

Some of the questions that have arisen during LNC methodology development are of broad interest, and should be debated outside the rather technical discussion of setting an LNC methodology. In particular, the question of how to meet the cost of adapting our networks for a future where the prosumer is the norm, and how those costs should be shared, is a broad societal question that deserves general discussion.

Additional research needed

This work highlights the following areas where additional research and debate is desirable in order to refine the recommended method:

- Calculating the value of local generation and storage in reducing replacement investment;
- Calculating the network costs associated with increasing DG penetration;
- Discussion of how the above costs of DG should be borne in the context of an evolving electricity network; and
- Refinement of the value setting and benefit sharing parameters to ensure that the LNC is sufficiently targeted to incentivise generator investment and operational behaviour.
- Exploration of user behaviour aspects in terms of price signal sensitivity in responding to an LNC, including investigation of whether an LNC is likely to be passed through to consumers.
- Calculating the portfolio effects and average diversity of the distributed generation portfolio.
- Further examining the effects of the miss-match in transmission and distribution cost reflective network pricing methodologies to assess the most appropriate way to include avoided transmission costs.

CONTENTS

Tables and figures

1 INTRODUCTION

The project *"Facilitating Local Network Charges and Virtual Net Metering"*, led by the Institute for Sustainable Futures, at the University of Technology Sydney, and funded by the Australian Renewable Energy Agency (ARENA) and other partners, brings together consumers, researchers, electricity providers and government to help level the playing field for local energy generation and prepare for the electricity grid of the future. The project is researching the impacts of local network charges for partial use of the electricity network, and Local Electricity Trading (LET, also known as Virtual Net Metering) between associated customers and generators in the same local distribution area.

A Local Network Credit (LNC) has been adopted as the means to deliver partial network charges in this project. Two key deliverables of the project are the development of a proposed methodology for calculating an LNC, and five virtual trials which of the effects of an LNC and LET on the economics of local energy projects. This paper outlines ISF's recommended methodology for calculating the value of an LNC.

1.1 Context

The electricity market is changing as technologies such as solar panels and battery storage improve and become more affordable. Many consumers are interested in not only using electricity, but trading with the grid and with each other, becoming 'prosumers' who generate some or all of their own electricity and sell the excess back into the market.

Improving the business case for small-scale, local generators (LG) to sell electricity locally, by offering innovative tariffs and billing arrangements, could unlock substantial new clean energy potential and reduce the negative impacts of customers taking their load off the grid. To give an example, small to medium businesses (such as local councils or universities) may want to generate electricity at one site and use it at another site nearby, using only a small proportion of the distribution network.

Network businesses are currently unable to offer a tariff to reflect partial use of the network to transport electricity between nearby sites, which may be as close as two meter points in the same building, or on two sides of a road. Electricity retailers do not routinely offer the capability to "net off" energy generated at one site at one or multiple other sites.

This means that local generation is commonly sized to match the lowest onsite electrical load to minimise grid exports, reducing economies of scale and operating efficiency. The existing market structure incentivises local generators to maximise the amount of energy being generated and consumed 'behind the meter'. This may result in inefficiently high levels of private sector investment in the equipment to avoid using the grid altogether, or equipment that duplicates network infrastructure (private wires).

1.2 What are local network charges?

Local network charges are reduced network tariffs for electricity generation used within a defined local network area. This recognises that the generator is using only part of the electricity network and reduces the network charge accordingly. Following previous work on the practicality of applying a reduced network charge for electricity sourced locally, and paying a network credit to local generators, the latter was recommended as a means to deliver reduced network charges for local electricity (Rutovitz et al. 2014), and is the mechanism investigated in this project.

Local Network Charges

A Local Network Credit (LNC) seeks to address inefficient outcomes in the NEM whereby LGs that provide or have the capability to provide benefits to the network are not currently incentivised to do so. LG is currently being deployed at significant scale, and an LNC provides a lever to steer its operation and deployment in a manner that has the greatest system benefit.

To date network credits for local generation have been applied systematically in the UK, and to a limited extent in the US. See Appendix in Section for more detail on how and where LNC style mechanisms have been applied.

1.3 What is being done in Australia – the ISF project

The ISF project is researching the impacts of both reduced 'local network charges' for partial use of the electricity network, and 'Local Electricity Trading' (LET, also known as Virtual Net Metering) between associated customers and generators in the same local distribution area. The centrepiece of the research is five 'virtual trials' of local network charges and LET in New South Wales, Victoria and Queensland. It is the first time local network charges have been tested in this way in the Australian market.

Figure 1: The virtual trials

The LNC methodology and the virtual trials will feed into economic modelling of the effects of an LNC, in order to gain better understanding of the scale of costs and benefits likely to ensue, the effect on future rollout of efficient local generation, and the implication for distribution and transmission networks.

The introduction of local network charges and LET is expected to unlock substantial new local energy resources, including additional renewable energy potential. The intended outcomes of the project are:

a) Five virtual trials of local network charges and VNM.

b) A recommended methodology for calculating an LNC.

c) An improved understanding of the metering requirements and indicative costs for the introduction of VNM.

d) Economic modelling of the benefits and impacts of an LNC.

e) Increased understanding by stakeholders of the requirements for the introduction of local network charges and VNM.

1.4 The rule change proposal for an LGNC

The City of Sydney, Total Environment Centre and the Property Council of Australia submitted a rule change request to the Australian Energy Markets Commission (AEMC) for the Local Generation Network Credit (LGNC) on July 14th 2015. The rule change request was informed by work previously commissioned by the proponents and conducted by ISF in 2014 on the options for calculating the benefits and costs of LG. The results of the ISF project feed directly into the AEMC's consultation on the rule change proposal.

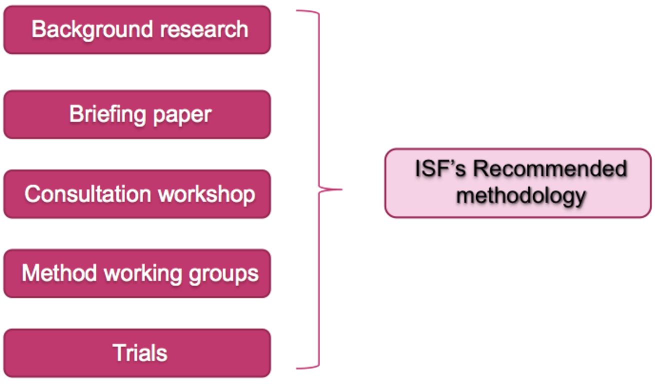
2 METHODOLOGY DEVELOPMENT

The recommended methodology to calculate an LNC is the culmination of 12 months of research and consultation during this project, combined with the outcomes of previous research on LNCs.

2.1 Process

Initial desktop research was undertaken to review methodologies currently in operation internationally and in Australia. A detailed briefing paper was produced that outlined ISF's proposed approach to calculating the value of an LNC and identified unresolved issues (Langham et al. 2015). Participants in the methodology workshop held on 24 August 2015 in Sydney discussed these methodological issues in calculating the LNC.

Figure 2: Methodology development



The purpose of the workshop was to:

- Agree on two methodologies to apply in the five virtual trials of the LNC; and
- Gain better understanding of the issues involved in developing a robust, workable and effective methodology.

Major consultation questions were discussed at the workshop and remaining issues were dealt with through methodology working groups.

In addition to the processes outlined above, ISF took part in a series of AEMC consultation workshops on the proposed rule change for an LGNC. Feedback from these workshops was also taken into consideration when deciding on a recommended methodology.

2.2 The methods taken to trial

Based on the outcomes of the workshop and working groups, ISF took forward two methods for testing in the trials:

1. A volumetric tariff
2. A combined volumetric and capacity tariff,

These two methods were selected for several reasons:

- As all international precedents use volumetric methods, it was decided that trailing at least one pure volumetric method was important.
- Most distribution tariffs for consumption in Australia have a combination of volumetric and capacity (peak demand) charges, and there was seen to be merit in an LNC that rewards generation in a way which mirrors the way consumption is charged. Two different combined capacity and volume tariffs had been proposed in the briefing paper, a 'bottom up' method in which each step was derived from first principles, and a 'mirror' method in which each step reflected as closely as possible consumption tariffs. It was thought there would be insufficient difference between "bottom-up" and the "mirror" combined volumetric-capacity methods, so that trialling both would offer less valuable insights.

- Stakeholders agreed that volumetric tariffs were much easier for customers to understand, and less complex to apply. We wanted to determine through the trial whether the value outcome for of the tariff is substantially different for a volumetric and combined volume-capacity tariff.

2.3 Additional value calculation

ISF proposed in the briefing paper to use the LRMC exactly as calculated for tariff setting as the basis of the value calculation for an LNC, however stakeholders expressed concern that it would not deliver the appropriate value to the LNC in the current investment environment (a recent over investment in network capacity resulting in lower LRMC values).

Participants agreed that it would be practical to stipulate the same method be used to calculate the LRMC for LNC setting as for the tariff setting for the purpose of trials, but were less sure this is how it should be done in the long term. There was considerable interest in the project investigating alternatives for value calculation.

Based on this feedback, ISF contracted Energeia to undertake modelling on an alternative value calculation, using a standard Average Incremental cost (AIC) method to calculate the LRMC value. This alternative AIC value was used for sensitivity testing in the trials, and used in the economic modelling of the LNC.

2.4 Applied as a credit to the generator

There was originally extensive discussion of whether the LNC should be transactionally applied as a *reduced charge* to the electricity consumer, or as a *credit* to the generator. Following consultation in late 2014 (Rutovitz et al. 2014), there was a clear response that it should be a credit to the generator, primarily because of the ease of implementation.

The current rule change proposal was submitted on this basis for a Local Generation Network Credit. The proposed LNC is fundamentally a mechanism to deliver appropriate charges for partial use of the network and reward network benefits provided by local generation. The proposal stipulated a credit to the generator because of the significant complications involved in implementing a reduced charge on consumption, as this would require keeping a register of local transactions.

An LNC methodology should therefore focus on valuing the network not used by local electricity flows. A consequential effect may be *long-term* network cost reduction even in those areas that are currently not constrained. The ISF project is investigating the extent to which an LNC can reduce the repayment of sunk costs on a per customer basis, by retaining a larger transactional base.

While there are still valid conversations to be had over geographical and timeframe aspects of value calculation, clarifying the original rationale emphasises the importance of considering the value of the LNC relative to the cost of network services to the consumer, and not just relative to the near-term savings made by the NSP.

2.5 Principles of an LNC

This section outlines the core principles that should underpin a methodology for calculating LNCs.

According to the rule change submitted to the AEMC on 14th July 2015, two key features of the proposed Local Network Credit are that the credit should:

- "[provide] a **price signal** for exported energy"
- "..**reflect 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

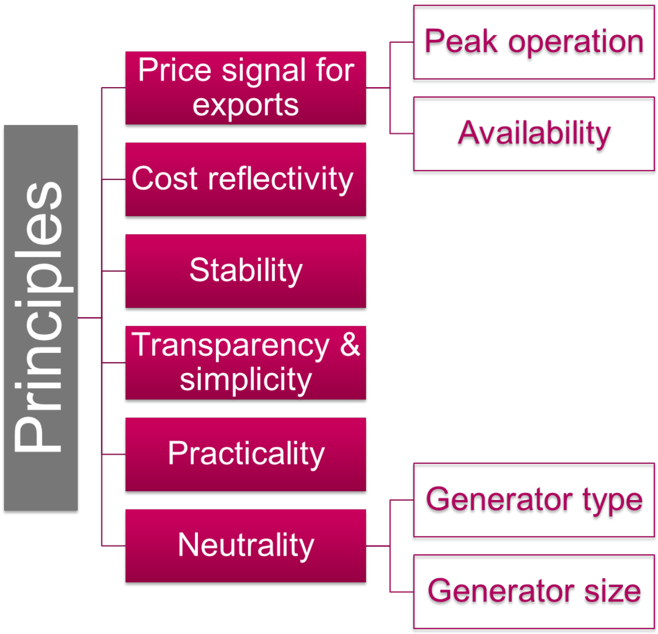
transmission costs that would otherwise be passed through to end users." (Hoch & Harris 2015)

This is in line with the general economic principles of pricing infrastructure: " the promotion of efficiency requires the setting of prices that encourage the optimal use of existing infrastructure assets while signalling to users the cost of an additional unit of a good or service." (Kemp et al. 2014).

An underlying principle of an LNC is of equity of pricing and outcomes for users who are unable to access distributed generation technologies. In the absence of an LNC there remains an incentive for those who can self-supply to minimise the network tariffs they pay, through load defection. This leaves other consumers to bear increasing prices as network charges are levied on fewer remaining consumers. An important rationale for any LNC methodology developed is that it continues to promote efficient use of existing infrastructure and not defection from it, thereby promoting tariff equity.

These basic principles are listed below, with some secondary principles.

Figure 3: LNC principles



Together these principles can be used to test the effectiveness of a particular methodology, which should have the following features:

- **Provision of a price signal** to incentivise:
    - **Peak operation:** at the times when LG can provide the most benefit to the network in addressing peaks, and
    - **Availability and reliability:** of LG units during peak period.
- **Cost reflectivity:** the methodology should calculate the value of the LNC so that investments in both LG and network expansion meet load in an economically efficient manner.
- **Stability:** the LNC should be sufficiently stable and predictable to allow for sensible investment decisions and conform with the pricing principle of gradualism.
- **Transparency and simplicity:** the method should be transparent and easy for LG owners and operators to understand and respond to.

- **Practicality:** the methodology should be practical for NSPs (both transmission and distribution) and retailers to implement, and fit broadly within existing metering and billing systems.
- **Neutrality:** the LNC should be technology neutral, which implies:
  - Calculation on performance rather than type of generator
  - Applicability to LG across a range of sizes
  - Allowance for the contributions of many small generators, when considered in aggregate, to be incentivised in the same way as an equivalently sized larger generator with the same performance.
  - Incentivisation of LG exports to reduce system peak in the same manner that load reduction is incentivised (where there is the same impact on system use).

2.6 Benefits and Costs of LG

Table 1 sets out the commonly recognised benefits of local generation (LG) and whether and how each benefit was planned to be captured in the calculation of the LNC.

Table 1: LG benefits – whether and how these are captured in an LNC

CATEGORY	TO BE CAPTURED?	HOW CAPTURED
REDUCTION IN DISTRIBUTION COSTS:		
• Avoided or deferred augmentation	YES	LRMC of avoided capital costs
• Progressive downsizing of replacement infrastructure	NO	Ideally should be calculated as LRMC of avoided replacement costs, but data not available
• Reduction of associated operating cost expenditure	YES	LRMC of avoided operating costs
REDUCTION IN TRANSMISSION COSTS:		

CATEGORY	TO BE CAPTURED?	HOW CAPTURED
• Categories as per distribution above	YES	LRMC method as above
AVOIDED LOSSES: • Reduced energy generation requirement	NO	Currently addressed in voluntary arrangements for retailer Feed-in Tariff or buyback.
• Reduced upstream network capacity requirement	YES	Applied as uplift to capacity impact on LRMC of avoided transmission & distribution capital costs & associated operating costs
Network services: voltage & frequency support	NO	Addressed through Frequency Control and Network Control Ancillary Services (FCAS & NCAS) on transmission network. For distribution this an issue for future consideration.
Improving network utilisation: retaining long term network revenue in a declining demand environment	NO	Anticipate that a societal benefit is likely to exist here but is difficult to calculate and best to assume captured as societal divided

The question of how costs associated with high DG penetrations should be met was subject to a working group discussion, with four options put forward by ISF. The primary focus of the working group was whether and how such costs should be integrated into an LNC. It was clear that the discussion raised broader societal issues regarding how the cost of adapting the network for much higher penetration of LG should be shared, and the incumbent generator advantage implied in the current network configuration.

2.7 Probabilistic approach

The generators considered in this report include both dispatchable and non-dispatchable plant. Due to the scale of generation considered, generators are dispersed geographically and we consider it appropriate to treat them as a diversified portfolio. We treat generation at a particular location at a particular point in time as having a probability of abating a peak event. This probability is primarily driven by DNSPs estimates of peak windows due to assessments of the load profile.

2.8 Precedents Investigated

Six methodologies for LNC calculation were reviewed in the methodology briefing paper (Langham et al. 2015). The approaches and the strengths and weaknesses of the six different methodologies for calculating LNCs internationally are shown in the Appendix.

A number of elements from these precedents have influenced the development of our recommended methodology. The main elements adapted for use in the preferred methodology presented in this paper are:

- **Voltage level of connection to allocate value:** Allocation of network value by voltage level as used by the UK once again provides the framework that is used in our methodology development.
- **Probability of peak occurring:** Ausnet and the UK both incentivise LG operation at particular times based on the probability of generation in those times assisting with

meeting peak periods, and we have adopted this as the means to send time based signals.

3 TRIAL OUTCOMES: IMPLICATIONS FOR LNC

3.1 LNC tariff values calculated for the trials

In the trials we tested both a volumetric tariff (method 1) and a combined volume and capacity tariff (method 2).

The LRMC and the period (peak, shoulder, off-peak) periods are key inputs to the LNC rates. Each network selected their own set of peak, shoulder and off-peak periods and the probabilities of the peak occurring during those periods.

The values for each network are shown in Table 2 and Table 3 for each connection level (remembering that the LNC is only paid for the network values above the level at which the LG connects). With the exception of Powercor, all networks used the same peak, shoulder and off-peak periods for the upper and lower tier calculation in the volumetric method. Most networks simply applied their existing peak shoulder and off-peak cycle used in customer billing.

Some networks, such as Powercor and Ergon chose relatively tight peak periods. This can be seen by the relatively high value available in quite a small proportion of the year in the charts below. This is contrasted with application to Essential Energy's very long standard peak and shoulder periods, which resulted in both periods having very similar 'smeared' LNC values, given a relatively high likelihood of a peak event happening in either period.

Table 2: LNC values – volumetric method

	Ergon			Powercor			Essential			Ausgrid		
Connection level	1	2	3	1	2	3	1	2	3	1	2	3
	c/kWh			c/kWh			c/kWh			c/kWh		
Peak	32.5	28.3	15.4	22.3	21.8	9.5	6.8	4.6	2.7	12.4	9.3	7.9
Shoulder	n/a	n/a	n/a	n/a	n/a	n/a	5.6	3.8	2.2	0.5	0.4	0.3
Off-peak	4.8	4.2	2.3	0.06	0.06	0.03	1	0.7	0.4	0	0	0

Figure 4 graphically shows the LNC value at the lowest connection level, i.e. the low voltage system, and the proportion of the year that value is payable.

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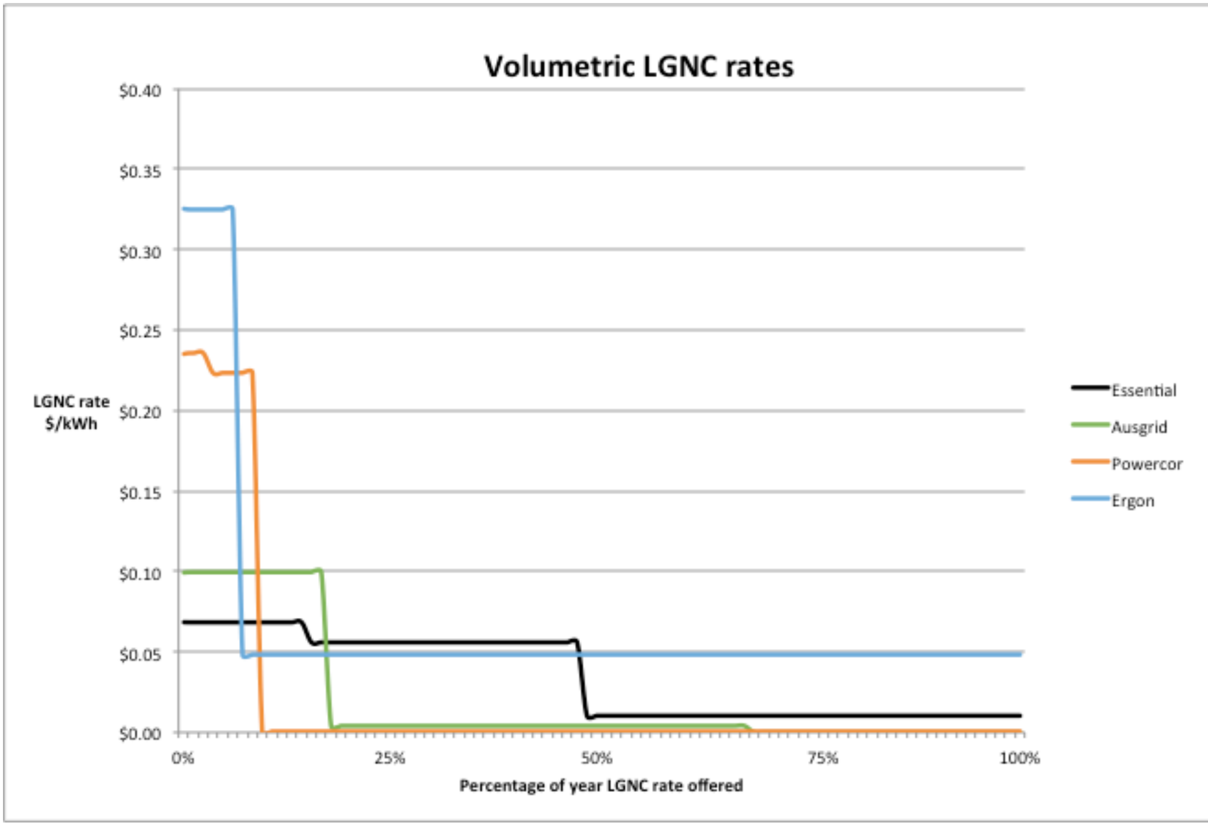
	Ergon			Powercor			Essential			Ausgrid		
Connection level	1	2	3	1	2	3	1	2	3	1	2	3
	c/kWh			c/kWh			c/kWh			c/kWh		
Peak	32.5	28.3	15.4	22.3	21.8	9.5	6.8	4.6	2.7	12.4	9.3	7.9
Shoulder	n/a	n/a	n/a	n/a	n/a	n/a	5.6	3.8	2.2	0.5	0.4	0.3
Off-peak	4.8	4.2	2.3	0.06	0.06	0.03	1	0.7	0.4	0	0	0

Figure 4: Volumetric LNC by network rates and percentage of year they are paid (connection level 1: low voltage)



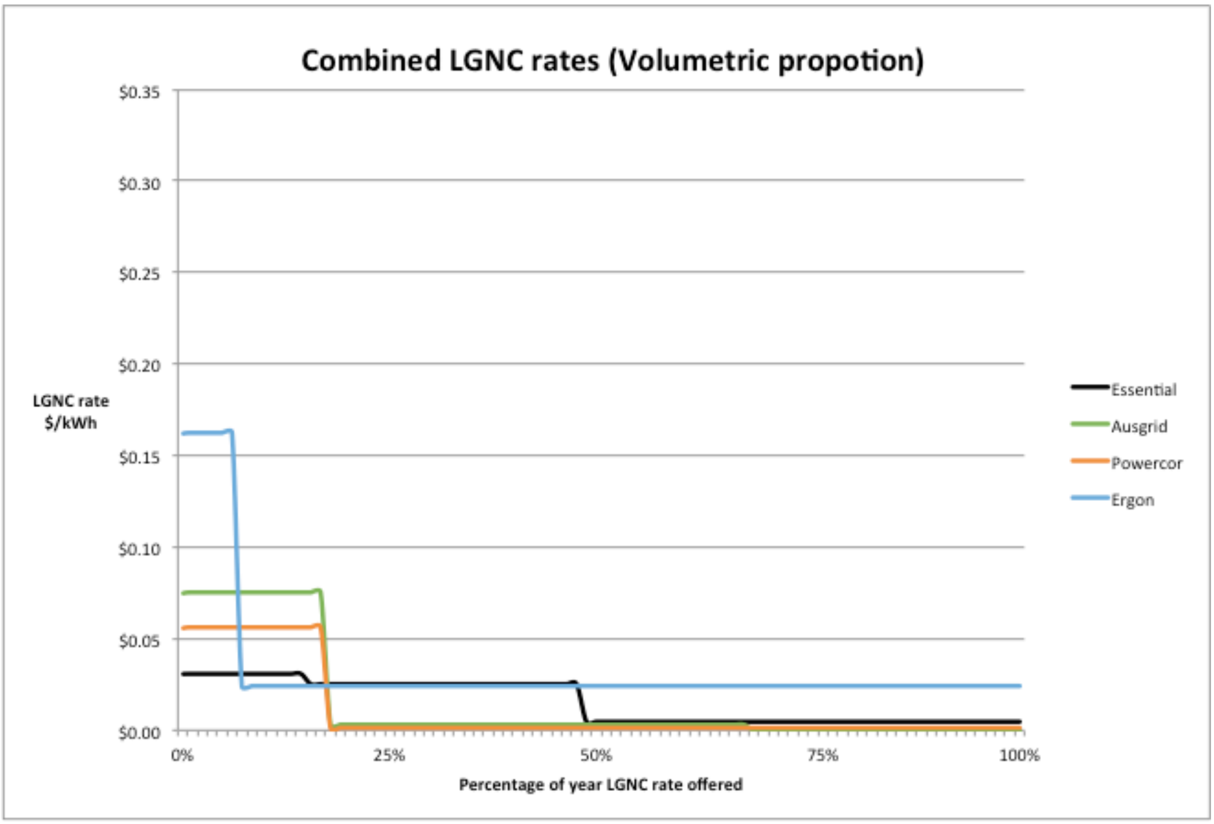


Table 3: LNC values – combined volumetric and capacity payment method

	Ergon			Powercor			Essential			Ausgrid		
Connection level	1	2	3	1	2	3	1	2	3	1	2	3
VOLUMETRIC PORTION	c/kWh			c/kWh			c/kWh			c/kWh		
Peak	16.2	14.2	7.7	5.6	5.5	3.8	3.1	2.1	1.2	9.4	7.0	6.0
Shoulder	n/a	n/a	n/a	n/a	n/a	n/a	2.5	1.7	1.0	0.4	0.3	0.2
Off-peak	2.4	2.1	1.1	0.1	0.1	0.1	0.5	0.3	0.2	0.0	0.0	0.0
SUPPLY PAYMENT	$/kW/day			$/kW/day			$/kW/day			$/kW/day		
Based on minimum generation in defined period	3.35	2.92	1.59	0.46	0.45	0.31	0.45	0.30	0.18	0.14	0.11	0.09

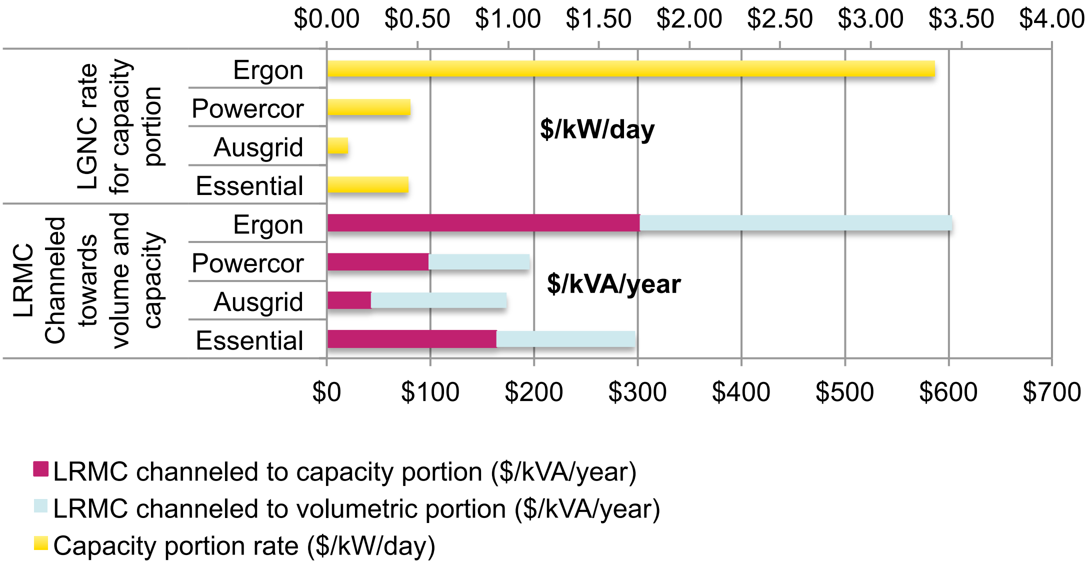
The combined LNC (Method 2) involved splitting the LRMC into volumetric and capacity portions. The relative share of this split was applied on the basis of the existing split in consumption tariffs between kWh and kW (or kVA) based tariffs. The capacity portion of the combined LNC was influenced both the DNSPs' LRMCs and the percentage allocation of the LRMC towards the capacity payment. Figure 5 shows the amount of total LRMC per network, and the proportion assigned to capacity and volumetric payment in the combined tariff, and the resulting potential payments in $/kW/day.

The capacity rate was offered based on generator availability during peak periods only. For Ausgrid and Essential this was year-round, whereas Powercor had winter and summer peaks and Ergon summer only.

Once again Ergon's rates were the highest due the high LRMC of the Ergon network and the summer only payments. Ausgrid's capacity portion was the lowest of the networks in our trials, which was influenced as much by the lower allocation of LRMC towards the capacity portion, and by Ausgrid's lower LRMC.

Payment of the capacity portion of the combined LNC was based on the minimum generation event over a specified period, which was usually one month. Some networks chose to average a few minimums over the period. However, in all cases the generator only needed to be out for maintenance or resource variability for a few hours in the peak period to be excluded from the payment. For those networks that chose to use a year long period to calculate the payment, this meant any outage in peak periods over the year would almost certainly result in a zero payment.

Figure 5: Capacity portion of combined LNC rates

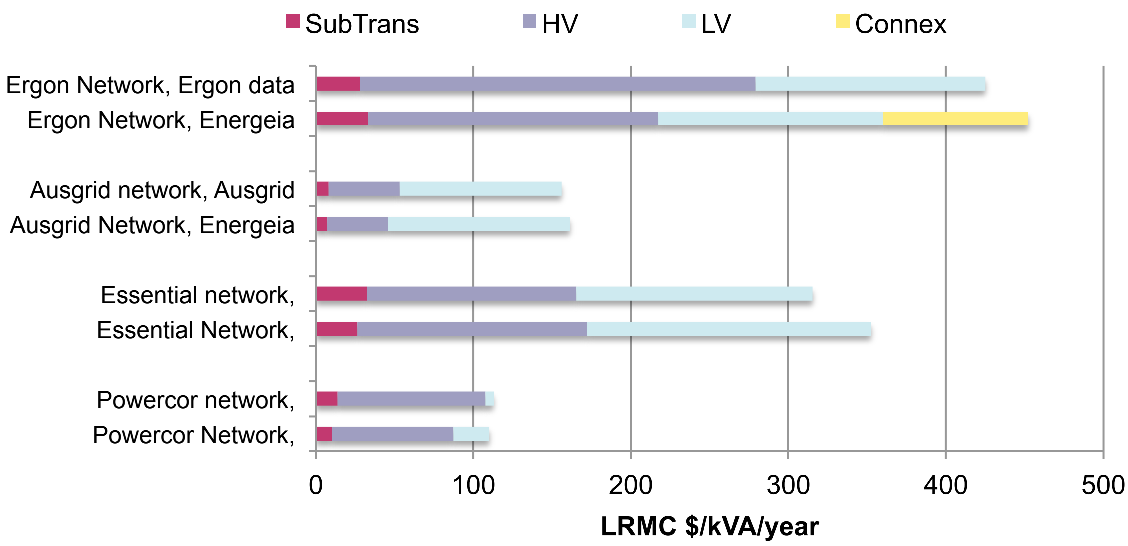


3.2 Additional LRMC modelling

As part of the trials, Energeia was commissioned to produce a model as an alternative basis for estimating the LRMC of the networks. This provided a way of normalising the time horizons and inclusions the different networks had used to calculate the LRMC, and as a potential second method for setting the value for the LNC.

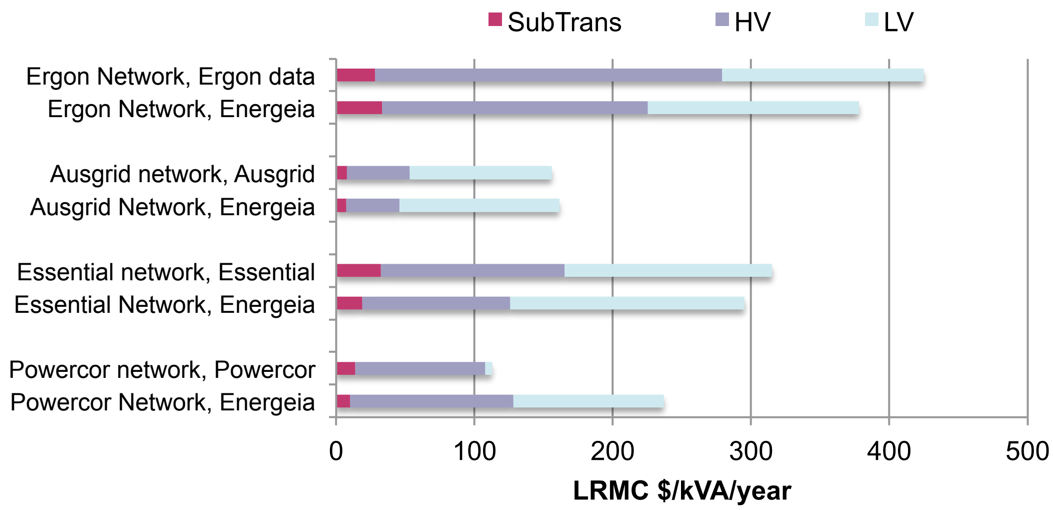
Energeia calibrated its model against published network LRMCs, meaning that when inputs are set to match the assumptions used by DNSPs, the resulting LRMCs are nearly identical to those provided by network businesses. These calibration outcomes are presented in Figure 6. *Note that comparisons of these* Figure 6 *outputs should not be made across different DNSPs, as inputs such as cost inclusions/exclusions and time horizons are not consistent.*

Figure 6: Energeia-calculated vs network-supplied LRMCs (using settings applied by each DNSP)



The Energeia model allowed us to assess LRMC results based on exclusions and assumptions that are set by the user. Altering these from the DNSPs own assumptions leads to an assessment of DNSP LRMC under a standardised set of assumptions (25-year time horizon, 10% probability of exceedance, and the including of the impacts of connection costs on replacement, augmentation and operating costs, but excluding the direct costs of new connections).

Figure 7: Energeia calculated vs network-supplied LRMCs (using consistent settings across DNSPs)



3.2.1 Discussion

After inputs had been standardised, the results showed that for all networks except Powercor, LRMC values were not significantly altered. This meant that the values produced by the networks or the Energeia tool would provide a strong foundation for the basis of the value to be signalled via the LNC, and confirmed that the LRMCs provided where not significantly sensitive to the altered assumptions.

The result for the Energeia modelling of the Powercor network showed significant variation between the two values following the change in input assumptions. This is the result of different methods to calculate the LRMC; both methods exclude the direct costs of new connections, however, only the Energeia calculation includes the ongoing non-direct augmentation and replacement costs on the shared network associated with those new connections.

In the case of Powercor, while results for subtransmission and HV networks are similar, Powercor's valuation of the LV network at approximately $5/kVA/yr is significantly different from the Energeia tool, when these ongoing non-direct augmentation and replacement costs associated with new connections are included.

Energeia's value may also include some non-demand driven augmentation expenditure that cannot be differentiated from RIN data, but is excluded from Powercor's LRMC trial calculation, such as bushfire related works. We note this difference is in the consumer's favour, as it will result in lower consumption tariffs, but also a lower LNC for the Powercor network.

We determined that the LNC methodology should continue to use the LRMC as calculated by networks and accepted by the AER, this means the consumption tariff LRMC will match the LNC LRMC, and minimise the opportunity for 'gaming' by generation proponents or networks.

Note that currently replacement/refurbishment investment is generally not included in NSP LRMC calculations and any avoided costs associated with these cost categories should be considered in future calculation of the LNC (refer to Section 5.2 for more detail).

3.3 Choosing peak periods to promote efficient cost/benefit signals

The ability of a tariff structure to efficiently signal to a generator the benefits of operating at peak times is predominantly determined by the peak period selected by the network. At one extreme, a flat rate across all hours of the year provides no signal at all. At the other extreme, an availability payment offered retrospectively for only those hours of the actual yearly system peak also does little to incentivise behaviour, as it provides no advance warning to generators. In between these extremes lie the possibility for DNSPs to set peak times that incentivise generation when it is useful on a probabilistic basis.

Networks in the trials selected between approximately 600 hours per year (7% of the year) and 1800 hours per year (20% of the year) as the nominated peak period, as shown in With the exception of Powercor, all networks used the same peak, shoulder and off-peak periods for the upper and lower tier calculation in the volumetric method. Most networks simply applied their existing peak shoulder and off-peak cycle used in customer billing.

Some networks, such as Powercor and Ergon chose relatively tight peak periods. This can be seen by the relatively high value available in quite a small proportion of the year in the charts below. This is contrasted with application to Essential Energy's very long standard peak and shoulder periods, which resulted in both periods having very similar 'smeared' LNC values, given a relatively high likelihood of a peak event happening in either period.

Table 2: LNC values – volumetric method

	Ergon			Powercor			Essential			Ausgrid		
Connection level	1	2	3	1	2	3	1	2	3	1	2	3
	c/kWh			c/kWh			c/kWh			c/kWh		
Peak	32.5	28.3	15.4	22.3	21.8	9.5	6.8	4.6	2.7	12.4	9.3	7.9
Shoulder	n/a	n/a	n/a	n/a	n/a	n/a	5.6	3.8	2.2	0.5	0.4	0.3
Off-peak	4.8	4.2	2.3	0.06	0.06	0.03	1	0.7	0.4	0	0	0

Figure 4. A peak window at the lower end of this spectrum will provide better signalling of generation value and thus an LNC more effective at targeting generation at peak events. This however must be tempered by a network's confidence in identifying a peak window with a sufficiently high peaking probability.

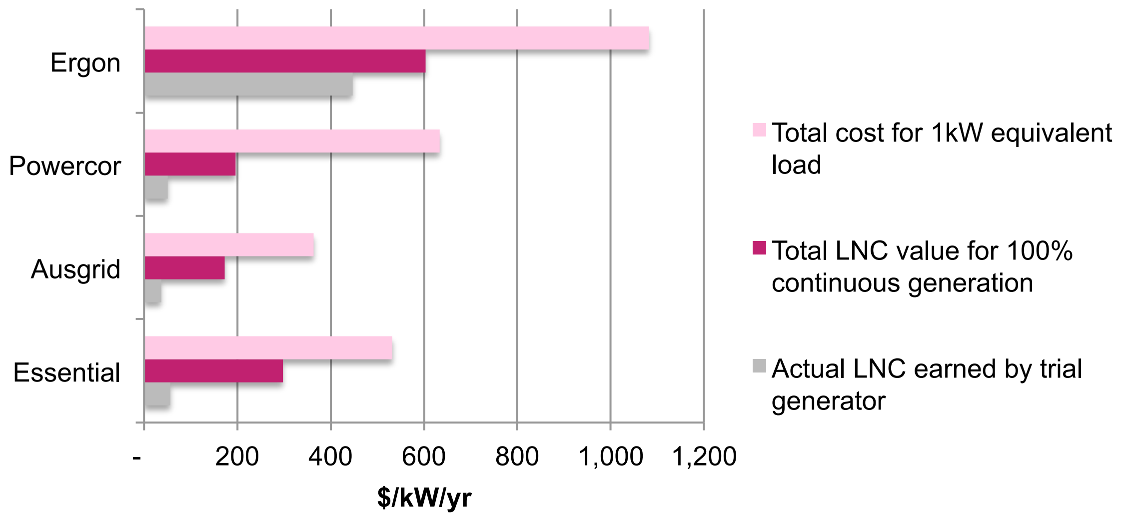
This finding has influenced recommendation 6.

3.4 Potential network value to be captured from distributed generators

We calculated the charges a continuous 1kW load would be billed in each of the trial network areas, and compared them to the calculated LNC that would be paid to a 1kW generator operating 100% of the time at the lowest connection level in those areas. These are shown in Figure 8, alongside the actual LGNC earned by a trial generator in that network area (generator type varies by trial).

In each case it was found that consumption tariff billing was substantially higher than the LNC, which is logical, in that for all LNC calculations one or more network levels are excluded. Additionally, no uplift factor for repayment of sunk capital is applied to the LNC as would be applied in regular consumption network tariff setting (Kemp et al. 2014).

Figure 8: Total value in LNC by network (LV connected generators)



The total LNC value ranged from approximately one third to a just over one half of the equivalent consumption charge, depending on the DNSP. Another way of conceptualising this is to say that the value of the network costs avoided when delivering energy from local generators is approximately one third to just over on half of the value of the network used to deliver energy from centralised generation plant.

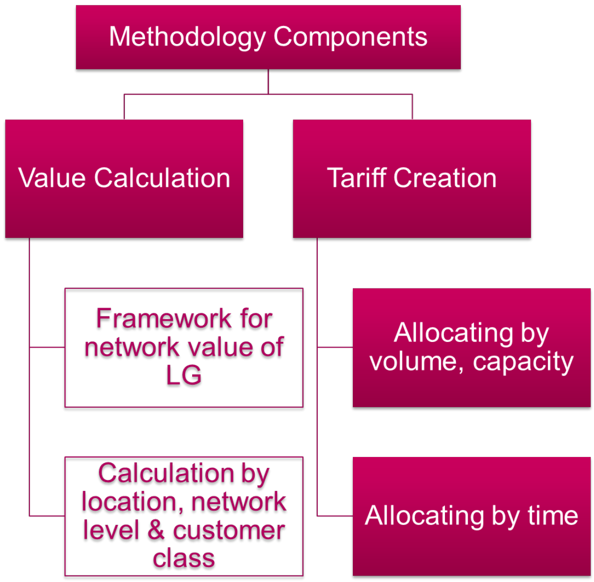
It appears that a generator with strong consistent performance has the potential to make significant contributions to network cost abatement. Using the LRMC values and calculations from our trials, a 1kW generator connected at the LV level has the potential to reduce peak costs by between $196 (Powercor) and $603/kW (Ergon) per year.

4 METHODOLOGICAL APPROACH: OVERVIEW

We identified the following steps in an LNC calculation methodology:

1. VALUE CALCULATION
    a. Framework for network value of LG
    b. Calculation by location, network level and customer class
2. TARIFF CREATION
    a. Allocating value to LG by volume, capacity, or both
    b. Allocating value to LG by time
3. OTHER ISSUES
    a. Treatment of LG costs
    b. Avoided transmission costs
    c. Avoided losses

Figure 9: Methodology components



We have assumed throughout that the general principles for cost reflective network pricing as applied to tariff setting should be followed in the calculation method for the LNC, unless there is a reason why applying these methods will lead to an inefficient or inequitable outcome in a particular instance. These principles are set out in general terms in advice published by the AEMC (Kemp et al. 2014).

Note that there is a methodological barrier in identifying the cost reflectiveness of network pricing because the network is broken up into separate operators for distribution and transmission. Almost all consumers experience a bundled price (except for network losses), because they receive a bundled service. So for the purpose of offering cost reflective tariffs for local generation, a bundling of all network costs makes sense from the customer's perspective. However, for the purposes of this paper, avoided transmission costs are discussed separately in Section 7.1 due to different implementation precedents.

Section 5 addresses two issues, the general approach taken to determining the value of the LG to the network, which by implication is the approach to calculating the LNC, and the specifics of how this can be applied to calculating an LNC. Section 6 addresses how to translate the overall value of the LNC into a tariff, and Section 7 the treatment of LG costs, avoided transmission costs, and avoided losses.

5 METHODOLOGICAL APPROACH: VALUE CALCULATION

5.1 Framework for network value of LG

Options considered

The two main alternatives for calculation of the value of LNC are:

- **Reference service approach:** The difference between current network charges and the lowest cost of provision of an alternative 'reference' service (i.e. a private wire). This approach is currently allowed for within chapter 7 of the Western Australia Electricity Access Code, and is the concept of the "prudent discount" mechanism in the NER, which is intended to prevent inefficient bypass of the transmission system.
- **LRMC of network services approach:** the avoided cost of network augmentation and replacement equates to the long run marginal cost (LRMC) of network services, This should include growth-related augmentation which is caused by an increase in demand (and therefore may be avoided as a result of LG or reductions in demand), and in the case of falling demand, any reduced replacement expenditure. Associated operational expenditure should be included. (Note that while this applies to both distribution and transmission, transmission is addressed separately in Section 7.)

Recommended method – LNC value setting

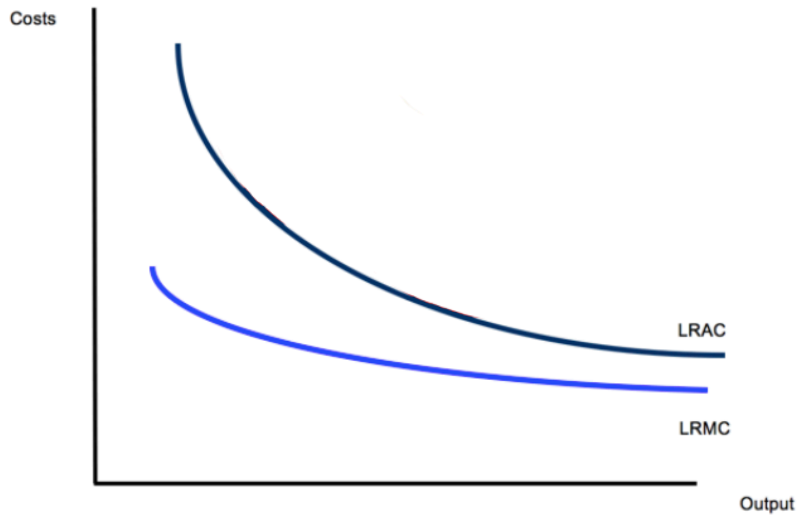
A central tenet of the rule change proposal on cost reflective pricing was to set "cost reflective tariffs in a manner that reflects the LRMC of providing network services". To maintain consistency with this principle, using the LRMC of network services is the preferred approach to calculation of the LNC.

This also recognises a key limitation of the alternative service approach, which requires a defined generator *and* a defined consumer, which is inconsistent with the proposed Rule Change to direct a LNC payment to the local generator, recently submitted by the City of Sydney, Total Environment Centre and Property Council of Australia (see Section 1.4).

The LRMC in natural monopolies tends to decline with scale, as illustrated in Figure 10. Thus using the LRMC alone as the basis of tariff tends to lead to under-recovery of revenue compared to the overall network costs. The normal practice is to mark up the LRMC based values in order to ensure NSP revenue covers costs (Kemp et al. 2014, pg 8).

We recommend that an equivalent mark-up is *not* added to the LNC. Rather, we suggest that any potential gap between the actual value of LG and the credited LNC value may be captured by all customers as a societal benefit from the introduction of an LNC.

Figure 10: Long Run Marginal Cost in natural monopolies (Riley 2015)



Recommendation 1: **Use LRMC as the basis of the value calculation for an LNC.**

5.2 LRMC calculation method

5.2.1 Options considered

The main alternatives for calculation of the LRMC are the Average Incremental Cost (AIC) and the perturbation method, which can have significantly different outcomes for the actual value calculated in different circumstances (Kemp et al. 2014).

Average incremental cost approach

The average incremental cost approach estimates LRMC as the average change in forward-looking operating and capital expenditure resulting from a change in demand. This is represented by the following formula:

$$LRMC\ (AIC) = \frac{\text{Present value (cost of new network capacity + associated operating costs)}}{\text{Additional demand served at future reference year}}$$

The AIC is defined as referring to an increment in demand, but a similar calculation could be undertaken for the reduction in capital expenditure on replacement (and the corresponding reduction in operating costs) resulting from a reduction in demand.

The UK CDCM method uses the AIC method to calculate LRMC to determine both the cost of network services and the avoided costs associated with LG.

The perturbation method

The perturbation method looks at the direct changes in forward-looking operating and capital expenditure as a result of a specific change in demand (kWh or kVA). This is represented by the following formula:

$$LRMC\ (perturb) = \frac{\text{Present value ((revised CAPEX + OPEX)} - \text{(original OPEX + CAPEX))}}{\text{Additional demand served at calculation year}}$$

While calculations are usually applied to an increase in demand, it can as easily be applied to a decrease in demand.

5.2.2 Recommended method – LRMC calculation

The AIC method is widely used for current NSP calculations feeding into tariff settings, as the perturbation method requires detailed information at a granular level.

The AIC method by definition is the average cost of demand increments, and smooths projected expenditure over the entire increase in demand. It will tend to underestimate the LRMC when the network is close to being constrained, as at that point a small increase in demand could trigger a large amount of expenditure. The perturbation method will tend to return very low values when the network is not constrained, and may underestimate the LRMC.

We consider the AIC method to be more suitable for calculating long run averages over customer classes, provided it can be adapted to provide the average LRMC of reductions in demand, as well as increments in demand.

We note however that recent changes in electricity law under the 'Power of Choice' rule change stipulate to DNSPs that either the AIC or the perturbation method may be used.(Australian Energy Market Commission 2014) ISF notes that the perturbation method can allow DNSPs to provide more locationally-targeted cost reflective pricing where it is efficient to do so, despite the additional calculation costs.

Rather than prescribing which method is preferable for LNC calculations, stakeholders agreed that it would be practical to stipulate the same method be used to calculate the LRMC for LNC setting as for the tariff setting for the purpose of trials, but they were less convinced that this is how it should be done in the long term.

ISF considers that if there is a mismatch in the way LRMC is calculated for cost reflective consumption vs cost (benefit) reflective generation then there is the potential for 'gaming' to occur both in the way that generators and consumers behave put also in the way it would allow DNSPs to pick different calculation methods for the cost/benefit of two events that otherwise have the same impact on the network, i.e. a generation event and an equivalent reduction in demand event. ISF considers this to create the potential for perverse outcomes.

An additional benefit is that as DNSPs improve the cost reflectivity of their tariffs, particularly with regards to locational accuracy, the locational accuracy LNC will automatically follow suit with no additional administrative burden.

It is important that the LRMC of downsizing assets as a result of long run reduction in peak demand, which is likely to be particularly important for transmission and sub-transmission elements in the future, is incorporated in whichever method is used. Note that this has not been possible within this project, as there was insufficient data on the cost savings that may be associated with downsizing. This is an important area of research as we move towards a network with large amounts of distributed generation.

Recommendation 2: Use the same method to calculate the LRMC for LNC setting as for the tariff setting.

5.2.3 Benefits of downsizing or retirement on the replacement cycle

Through the consultation process we learned that existing LRMC calculations undertaken by DNSPs do not measure the marginal cost in a downsizing of network capacity. Such a figure could be calculated in a similar way to the AIC or Turvey method discussed in LRMC calculation method. Some parts of the network (e.g. poles and switchyards) will likely see no benefit from a reduction in required capacity. Other assets such as transformers could realise significant savings if replaced with smaller units. Despite this, the key limitation of including such benefits in the LRMC at this time is the lack of information on the nature and magnitude of these savings.

Recommendation 2.1: When the marginal avoided costs of reduced investment in downsizing or retirement as a result of local generation are better understood by NSPs it should be included in the potential savings signalled via the LNC. The most appropriate method for including this is to assess the costs of replacement business as usual at the end of asset life and compare it with the costs of the smaller capacity replacement, or the retirement of assets in a meshed network.

5.3 Discounting and benefit sharing between generators and other consumers

The National Electricity Objective (NEO) is set out 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 price, quality, …[and other factors]"

If 'consumers' are defined to be non-generating customers, to achieve the NEO some of the long run benefit of reduced augmentation would need to be realised by the electricity consumer. If the full value of the LRMC of the avoided network is credited to the generator, societally the total cost of network would remain unchanged. A benefit-sharing factor is a means to ensure the value proposition of local generation is captured by both proponents and non-participating customers. It also can serve as a means of discounting the savings calculated for reduced augmentation, thereby ameliorating the uncertainty associated with both network costs and demand forecasts.

A discounting and benefit-sharing factor would be applied as a reduction in the LRMC that is an input to the LNC calculation. This would be a predetermined ratio, for example 80%. In this case, local generation would capture 80% of the calculated value it creates (to influence generator uptake and behaviour), and the remaining percentage would remain a discount to reflect uncertainties present in LRMC assessment and demand forecasting.

It is likely that an LNC would incentivise a significant amount of behind the meter generation, thereby reducing augmentation costs without attracting an LNC payment. In the economic modelling undertaken for this project, this effect increased the benefit of the LNC by a factor of six (Kelly et al., 2016), which it is assumed would be passed to all consumers in the in the form of reduced tariffs in the long term. The discount of 20% in the amount paid to the generator adds to the value accruing to non-generating customers[2].

The discount factor applied would need to allow sufficient value to be captured by the generator in order to incentivise the correct behaviour to realise the network augmentation savings. Based on the trials we expect that a minimum level to be retained by the generator would be in the order of 70%. However, further work would be required across a broader cross section of generators and a greater proportion should be payed to the generator if DNSPs find that a lower amount does not incentivise the desired export behaviour.

Recommendation 3: Apply a discounting and benefit-sharing reduction to the LRMC to allow for uncertainty present in LRMC demand forecasts and cost estimates.

[2] Under the Efficiency Benefit Sharing Scheme the customer and network business may share the 20% of value created by the local generation, however this sharing has not been the focus of our work.

5.4 Calculation by location, network level and tariff class

Local generation will avoid network costs for the network levels upstream of that unit. As such an LNC calculation needs to consider where LRMC is incurred across the different network levels.

Furthermore, different customer classes contribute to the total network LRMC in differing proportions. An LNC set for one customer class based on an LRMC calculation that includes other customer classes may result in cross subsidy and should be avoided. Work for the AEMC by NERA on economic pricing concepts describes allocating LRMC at a network level to each customer grouping (Kemp et al. 2014, pg 16).

This approach of costing by network level and tariff class reflects current tariff setting practice and thus should be familiar to all DNSPs in the NEM.

5.4.1 Recommended method – specificity of LRMC

Network Level and Customer Class

We recommend calculating LRMC for both customer class and voltage level of the network, resulting in \$/kVA/yr figures by network level and customer class. It should be noted that the LRMC of the whole network would be the weighted average of the individual customer class LRMCs.

To translate the LRMC values into an LNC for LG connected at a particular part of the network, it is necessary to then allocate the levels of the network being used by the LG. This is in effect the same as crediting the LRMC of the parts of the system *not used* by the LG. We recommend applying the following principle: LG should pay in full for the transport of power at the level of connection and below (i.e. ‘downstream’). It should not pay for the levels of the network above where it is connected (i.e. ‘upstream’), to the extent that the LG is available during system peak periods. This principle is the approach applied in the UK CDCM precedent.

How this principle is applied to the LRMC components is shown in Table 4.

Table 4: Components of LRMC forming LG local network charge, according to the level of generator connection location (credited components marked with a tick)

	Cost Category							
Generator Situation	Transmission	Sub-transmission line	HV Substation	HV System	LV Substation	LV System	System-Fixed	Non-System fixed
Co-Located (Same site)	✓	✓	✓	✓	✓	✓	✗	✗
LV System Connected	✓	✓	✓	✓	✓	✗	✗	✗
LV Substation Connected	✓	✓	✓	✓	✗	✗	✗	✗
HV System Connected	✓	✓	✓	✗	✗	✗	✗	✗
HV Substation Connected	✓	✓	✗	✗	✗	✗	✗	✗
Sub-Transmission Connected	✓	✗	✗	✗	✗	✗	✗	✗

Location

Each DNSP applies tariff setting for different regions differently. Typically, distribution networks do not differentiate between regions, although some split their territory down into a small number of pricing zones where there are large differences in the cost of supply. By contrast, transmission networks are highly location specific in their charging structure. We recommend the value is produced and applied for each relevant pricing zone, to reflect current tariff setting practice. The LNC should become more locationally specific in line with network consumption tariffs. In general we consider it important that both consumption tariffs and the LNC adopt a greater level of locational specificity over time to improve cost reflectivity of both types of tariff.

Recommendation 4: Assess LRMC based on customer class and network level to delineate parts of the network that particular generators may impact. While there was a range of opinions on how location specific the credit should be, it was determined that the LNC should move towards locational specificity at the same rate that cost reflective consumption tariffs move towards specificity, so that the LNC uses the same LRMC calculations as used for tariff setting.

5.5 Adjustment for capacity impact of reduced losses

Network capacity upstream needs to meet not just the energy requirements of downstream loads but also the losses incurred in transporting the energy through the various levels of the distribution network. One kVA of generation at a low network level will avoid more than one kVA of network capacity upstream. The difference will be the ratio of the Distribution Loss Factor (DLF) at the generator connection point to the DLF at the upstream network level. It should be noted that Distribution Loss factors apply to the distribution network and Marginal Loss Factors (MLFs) to the transmission network. As this section of the calculation is referring to distribution network *capacity* only and not energy value, the DLF has been applied.

This step begins with locating the generator in the network by both network level of connection and by customer type. Then, the ratio of the loss factors is calculated for each network level above the generator connection point.

$$Adjusted\ LRMC_{upstream\ level} = Base\ LRMC_{upstream\ level} \times \frac{DLF_{Generator\ connection\ point}}{DLF_{Upsteam\ level}}$$

This methodology is not dissimilar to ActewAGL's avoided TUOS methodology (ActewAGL 2013). The key difference is that it is applied as a ratio to each network level as opposed to only a single ratio back to the transmission connection level.

An example is presented below for the case of a small commercial customer's generator connected at the distribution sub level.

Table 5: Hypothetical example of proposed application of uplift of capacity impact due to reduced losses

LRMC ($/kVA/yr)	Base LRMC $/kVA/yr for customer class	Distribution Loss Factor	Loss factor ratio to generator connection level	Adjusted LRMC per kVA exported at generator connection level
Subtransmission	24	1.0019	1.0330	24.8
HV Zone Substation	33	1.0052	1.0296	34
HV Feeder	69	1.0293	1.0055	69.4
Distribution Sub	48	1.0350	1	48
LV	93	1.0490	n/a	n/a
TOTAL	257			

Recommendation 5: Adjust the LRMC for each network based on generator connection point to account for the capacity effects as a result of losses using the following formula, noting that this adjustment will need to be calculated for generator connection level within each customer class.

$$Adjusted\ LRMC_{upstream\ level} = Base\ LRMC_{upstream\ level} \times \frac{DLF_{Generator\ connection\ point}}{DLF_{Upsteam\ level}}$$

6 METHODOLOGICAL APPROACH: TARIFF CREATION

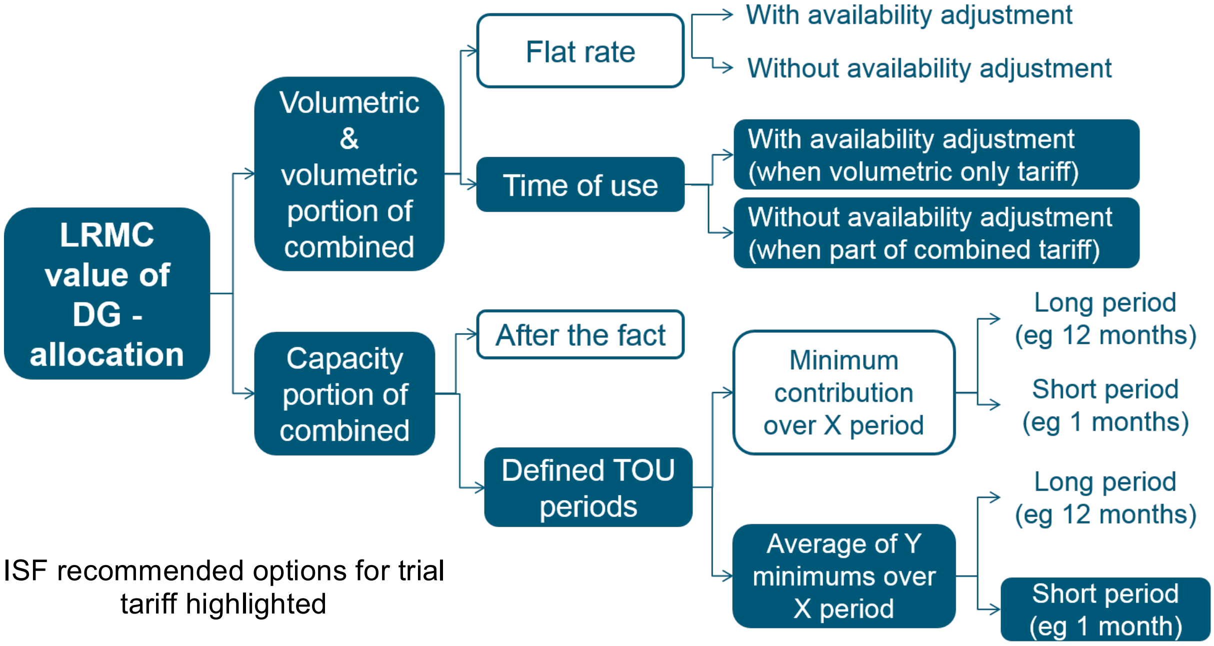
6.1 Volumetric or capacity or both?

6.1.1 Options considered

Once the overall value of the LNC has been calculated, the next step is to allocate the value to customer classes via a specific tariff. A fundamental decision is how the tariff is paid, with the three options being volumetric, capacity, and both volumetric and capacity. The main characteristics and pros and cons of the three alternatives are summarised below.

There are subsequent calculation options for how volume and capacity payments are applied, which have a significant impact on the tariff effectiveness. Figure 11 shows the decision tree associated with volumetric and capacity payments. Dark blue shaded boxes indicate the approach adopted in the trials.

Figure 11: Decision tree for volumetric and capacity payments



Option 1: Volumetric payment alone

A volumetric payment may be applied as flat rate or Time of Use (TOU). We assumed that TOU would be adopted, as flat rate does not meet basic principles of efficiency as it does not incentivise operation at times that reduce network costs.

A TOU payment may include an adjustment for generator availability. For example, the UK's CDCM method applies an "f" factor by generator type, while the Minnesota method attempts a uses actual performance-based aggregate availability in determining the value of the generation unit. [3]

The main **advantages** of volumetric payments are:

- The only two systematic **precedents** for LNC tariffs are both paid via a volumetric payment (see the UK CDCM method and the Minnesota method in Appendix A)
- **Implementation** is straightforward, as TOU volumetric payments require only an interval export meter
- **Transparency and stability**: once the tariff is calculated it is understandable and provides a stable environment for LG investment decisions
- **Incentivising performance:** volume payments structured on a TOU basis provide a price signal for generators to operate during these pre-identified periods

Potential **disadvantages** – depending on the detail:

- **Allocative efficiency:** a volumetric payment based on the LRMC should be cost reflective overall, but the distribution of value to particular LGs may be incorrect.

Outstanding issues – depending on the detail:

- **Availability adjustment:** a volumetric payment would be technology neutral. However an availability adjustment is required to incentivise generator availability. To remain technology neutral an Australian LNC would need an availability adjustment based on actual generator availability as a substitute for the UK CDCM "F" factor, which sets a pre-defined adjustment for availability (breaking the neutrality principle).

Option 2: Capacity payment alone

A capacity payment is given for the provision of capacity during defined periods, with many options for defining the period and other parameters.

The main **advantages** of capacity payments are:

- **Cost reflectivity:** Capacity payments are the most obviously **cost reflective** payments, as network capacity peak periods are the main driver of marginal costs.
- **Incentivising future performance:** capacity payments may offer a strong **price signal**, as LG is only paid to generate at those times most useful to the NSP.

Potential **disadvantages** – depending on the detail:

- **Applicability**: Many smaller customer classes do not currently have capacity payment components, metering and billing infrastructure may not be in place to apply capacity payments, and the concept may be more difficult to communicate to residential or small commercial customers.
- **Incentivising performance:** if the time period is very long, or if the allocation to time is *after the event* (in which an event is defined as the top peak day(s) for the year, or the top 30 minutes for the month) the ability to send an effective price signal is greatly compromised, as the LG does not have the information to modify behaviour.
- **Transparency and stability:** the payments will be difficult to understand or use as the basis for investment, as the outcome would be extremely variable according to

[3] The Minnesota calculation is done according to the generation profile of the class of generators for a full year or set of sequential full years. Where the data is not available the Minnesota method prescribes the simulation methods to be applied.

the design details chosen. As different NSPs apply capacity charges in different ways, it is perhaps less likely that a consistent approach will be agreed. This could lead to considerable variation between NSP areas, and potentially between regulatory periods.

- **Neutrality**: while capacity payments appear to be technology neutral as they reward performance, an 'all-or-nothing' approach to capacity charges across a whole peak period would not, in effect, be technology neutral. For example, requiring capacity across an entire 2-8pm peak period would always result in a zero credit for Solar PV, yet a 4pm critical peak would still have been lowered by the PV contribution. This is an argument for allocating to LG value both capacity and volumetric components.

Option 3: Combined volumetric and capacity payments

Combining both a volume and capacity payment may address many of the concerns that attach to one approach or another, providing the best aspects are taken from each. A proposed combination is shown in Table 6 and is:

- A TOU volumetric payment, without an availability adjustment (as availability is addressed through the capacity payment component); and
- A capacity payment according to minimum availability during defined peak periods.

If a combined volumetric and capacity method is used, it is assumed that the LRMC and allocation by customer class and network level would be the same as for the volumetric calculations, with the exception that there would be no need for an availability adjustment.

ISF considered multiple options in assessing how to split the LRMC value that a generator may be credited between a demand (per kVA or per kW) and volumetric (per kWh) LNC structures.

The combined volumetric tariff ISF determined was practical to implement and appropriate for the trials was to split the LNC LRMC based on the percentage split that networks expect to use when recovering costs from demand and volumetric tariffs (per kWh). This was dubbed the 'mirror' method.

Networks would then be given discretion as to whether a single minimum generation event in a period was used as the crucial event or if an average of a certain number of minimums was more appropriate. ISF determined that it was appropriate that a reset period of 1 month was an appropriate maximum length of time. For the trials most networks used a single minimum event in a month as the basis for the capacity portion of the combined tariff

The key advantages of the mirror method are that it reduces the complexity of setting the LNC for each NSP, and avoids duplication of effort. It is also intuitively equitable and easy to understand. The key disadvantage is that it is only as cost-reflective as the LG customer's tariff, which may not be very cost reflective currently, but will increasingly become so.

6.1.2 Methods tested in the trials

ISF took forward two methods for testing in the trials: the volumetric tariff and a combined volumetric and capacity tariff (Option 1 and Option 3), which are shown against the principles put forward in Table 7.

Table 6: Alternative methods assessed against tariff setting principles

Methodology	Operation	Availability	Cost Reflectivity	Stability	Transparency	Implementation	Neutrality
Volumetric TOU with availability adjustment	✓	✓?	✓	✓	✓	✓?	✓?
Volumetric TOU without availability adjustment AND Capacity Payment	✓	✓	✓	✓	?	?	✓

Table 7: Summary of the two tariff setting methods trialled

	VOLUMETRIC	COMBINED VOLUMETRIC + CAPACITY
Determine LNC value	LRMC of augmentation and (ideally) replacement CAPEX and OPEX (standard cost reflective tariff approach) with: • AIC / perturbation LRMC chosen as per customer class & network level • Include LRMC of downsizing and replacement	Same as volumetric method
Locational allocation of LNC value	Allocate by network level and customer class, as per standard cost reflective tariff approach	Same as volumetric method
Allocate between volume and capacity	All volumetric	Mirror existing consumption tariff split between volume and capacity
Availability adjustment	Split LRMC into a lower and upper tier based on lower levels of network experiencing peaks on a day/work week basis and upper levels experiencing system seasonal peaks. Assign upper level LRMC value to relatively few hours in the year.	Capacity payment rewards availability, adjustment not required
Time Allocation	Peak, shoulder and off peak by network tier (allow DNSPs to set different peak shoulder off-peak cycles for the lower and upper tiers). Adjust value of kWh in peak / off peak periods by DNSP estimated probability of peak occurring during that period.	Same as volumetric method
Include additional values/ costs	**Additional values:** Avoided TUOS value	Same as volumetric method

6.1.3 Discussion

We considered that the capacity methods trialled were likely to under-incentivise local generation and that volumetric methods trialled may over-reward local generation.

The trialled volumetric payment's over-rewarding of generation can be understood in the context of a generator or generator class that operates consistently during daytime hours but is not present at night, in a network area with a peak period spanning the afternoon into the evening. Generation will be present to alleviate peaking in the afternoon however will not assist in reducing the evening congestion, the actual peak value may change very little despite being shifted toward later in the evening.

The split of the network in to two tiers did not have the desired impact of providing a stronger availability signal in the volumetric payment. Only one network chose to set different peaking periods across the two tiers. As a way to set lower tier peak times for this case, we examined the average of five zone substations in the area, each servicing similar customers. However, the resulting peak times were similar to the system level peak times. As a result it was concluded that the two-tier approach added complexity but insufficient value to the methodology to warrant pursuing this method.

The trialled capacity payment's tendency to under-incentivise can be drawn out through considering the case of two generators, each of the same capacity, one operating for the first half of the peak period and one operating for the second half of the period. Both of these would receive a zero capacity payment due to the half-period outage. But when the two generators are considered as a portfolio, the network receives a consistent generation profile, but does not pay either a capacity payment.

In providing a recommendation we have considered which of the two methods can be best adapted to represent a middle ground. As the methodological development progressed it became clear that a volumetric payments and capacity payments are not as distinct as might be considered at first glance:

- A targeted volumetric tariff, when signalled through fewer and fewer peak hours, begins to behave very similarly to a capacity payment. Considering an extreme case of a volumetric tariff paid in a peak period consisting of only one hundred hours, ten hours or even one hour, reveals that the choice between a volume a capacity payment is in fact a spectrum, not a black and white choice.
- A capacity tariff, when reset on a shorter cycle, will behave similarly to a volumetric tariff. For example, consider a capacity tariff paid based on minimum generation level during a period with the period reset weekly, daily, or even hourly.

Both tariff structures are possible to hone or broaden, however we consider a volumetric payment is relatively easy to hone and target towards the necessary peak periods. Consultation with partners revealed that resetting a capacity tariff on a cycle more frequent than a billing cycle was seen as a more complex way of achieving the necessary market signal.

Recommendation 6: Allocate tariff value through a *well-targeted* volumetric TOU methodology. To provide the right availability incentive the DNSP should choose relatively few hours of the year for the peak period and ensure the peak period selected has a high peak probability. Further work would be required to determine exactly the number of peak hours each network should select, however we estimate that no more than 500 hours with greater than an 90% change of the peak occurring would appropriately incentivise the right level of availability and avoid unnecessary payments to generators not active at peak times. Networks would be prudent to refine the hours chosen and subsequent price signal provided with a view to what incentivises the desired behaviour from the prosumer market.

7 METHODOLOGICAL APPROACH: OTHER ISSUES

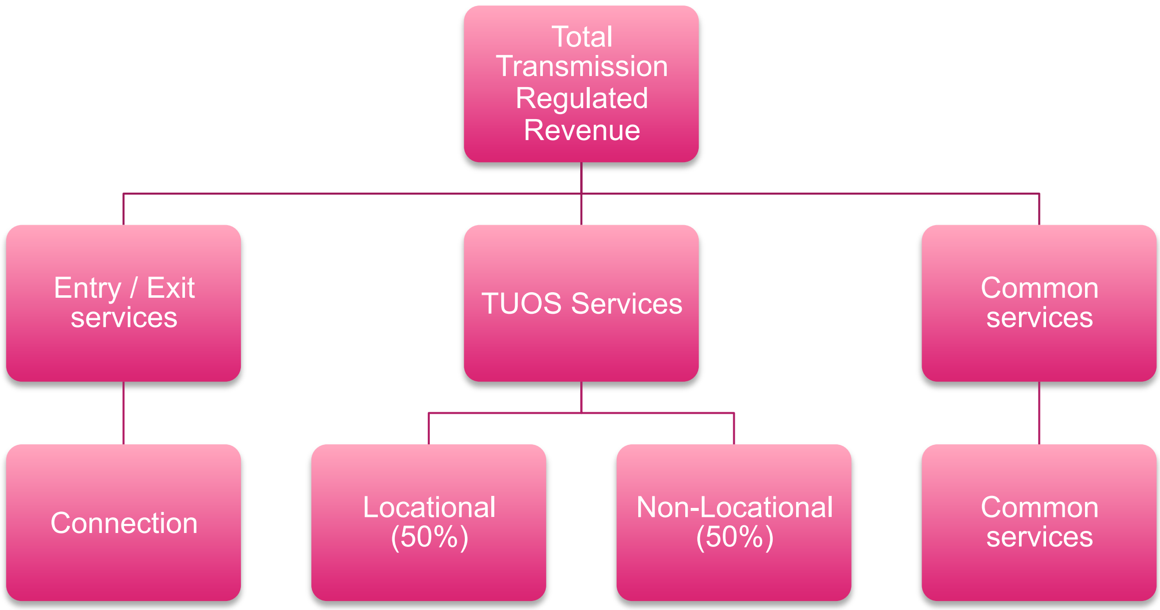
7.1 Avoided transmission costs

The value of avoided transmission costs is analogous to avoided distribution costs described in Section 5. However, as the LNC only considers LG embedded within the distribution network, no granular understanding of the cost by level of the transmission network is required.

TUOS charges are made up of three components: Usage Charges (Entry/Exit charges), TUOS Services Charges and Common Service Charges. TUOS Services charges are further split into locational and non-locational components (Figure 12).

As Section 5.5(h) of the NER stipulates that registered (large) generators are eligible to received avoided TUOS rebate, each network business has a method for calculating this value. The value of avoided TUOS is determined by each DNSP, and is intended to reflect reduced augmentation costs of the TNSP. The formula calculates to the reduced costs incurred by the DNSP at the point of transmission connection, as a result of the LG's existence. All avoided TUOS methodologies we are aware of in Australia use only the locational component as the basis of the avoided TUOS value.

Figure 12: Transmission cost breakdown



Source: Adapted from Powerlink (2015)

It should be noted that, with the exception of entry charges, all of the revenues in the above chart are recovered from loads (via charges levied on DNSPs).

A submission we received in the consultation process with Working Group members suggested the origin of the 50:50 split in TUOS services was originally intended to be a split between TUOS recovered from loads and TUOS recovered from generators. This has an intuitive fairness, as both are present in equal measure in a balanced electricity market. However, at the time, generators argued that as their investment decisions were already made there was little point in sending a generator locational price signal. That is, there was little scope for an existing generator to relocate and respond to that price signal. As a result we understand that the generators argued for the transmission company to recover these costs in a non-locational way from *loads*.

A further submission we received indicated that the non-locational component is adjusted by an overs/unders mechanism to correct for any under or over recovery from year to year. We understand this to be the basis for its exclusion from the standard avoided TUOS methodologies. So if this were refunded by a DNSP on the basis of it being avoided, it would only be re-couped in a later year via the overs/unders mechanism, leading to no real cost avoidance by the DNSP.

7.1.1 Options considered

The options for a transmission services avoided cost methodology are:

1. Apply the same **distribution LRMC calculation decisions (in Sections 5 and 6) to the transmission network**. The benefit of this approach would be in creating consistency and transparency of application between NSPs and for all levels of the network. The disadvantage of this approach are that it adds administrative complexity as it requires the LRMC to be calculated for transmission, and creates a new transaction involving the TNSP that differs but overlaps with the existing avoided TUOS calculation.
2. **Apply the inverse of all transmission charges.** This was proposed by one trial participant on the basis that local generation makes no use of the transmission network, and as such all transmission fees should be refunded. This method was heavily contested by DNSPs for the following reasons:
    a. Under an annual revenue requirement, some categories of transmission fees will not be avoided, a reduction in fees paid one period will lead to higher prices in the next period (although the same issue would also occur in Option 1 to a lesser extent).
    b. Even if a customer or group of local customers uses no net electricity, the connection to the transmission network provides the ability to receive frequency support and an additional level of supply redundancy.
3. **Utilise the existing avoided TUOS methodology of each NSP**, but apply it to all LG as opposed to just registered generators. The benefit of this approach is that there is a well-established method that DNSPs are comfortable with, although this is heavily contested by some local generation proponents. The negatives of this approach are that:
    a. The method may not be consistent (in that NSPs may have different methodologies);
    b. There is currently not full transparency in how this methodology is applied;
    c. The means of calculation may be more simplistic in how peak demand reductions from LG are treated than some of the options explored for DNSP capacity charges. This may be particularly true for variable output generators, and as such the method may not be technology neutral.
    d. Current methods calculate and reward peak generation availability ‘after the fact’ (post the peak occurring), which eliminates the ability for a generator to have advance notice of when their generation has value.

4. **Estimate avoidable LRMC from the parts of transmission tariffs that relate to network augmentation costs.** This method is similar to method 1 however is not based directly on LRMC and thus acts as a placeholder for LRMC information. This method only relies on TNSP published data. The value directed to the LNC is similar to an avoided TUOS methodology but also includes 'non-locational' components. Published TUOS prices relating to the locational and non-locational transmission costs (but not common services) are used as the inputs. This method has the following advantages and disadvantages:
    a. It represents a compromise between methods 2 and 3 with respect to how much value is attributed to the reduced requirements from the transmission network.
    b. The following arguments were raised regarding the inclusion of non-locational charges:
        i. As non-locational charges are a historic consequence of an original intention to split the cost recovery between loads and generators, it is important to consider if local generation would reduce transmission network congestion caused by transmission connected *generators*. Given that local generation will reduce the need for centralised generation we consider this to be reasonable.
        ii. The overs and unders mechanism, if unchanged in its application, would lead to perverse outcomes if the non-locational charges are included. This is because a saving by a DNSP of non-locational charges due to local generation is corrected for in the next regulatory period. This is driven by an increase in the non-locational charge component allowing the TNSPs to correct for its under-recovery. Thus the current overs and unders mechanism would mean that DNSPs do not realise cost reductions over the medium term.

For the trials, method 4 was selected on the basis that it could be calculated with entirely public information and that the value allocated represented a compromise between the desires of those on the generator proponent's side of the debate and the networks. In this selection we note the flaws that this is not necessarily an accurate estimate of LRMC and that for this to be fair in its treatment of DNSPs either the overs and unders mechanism would require alteration, the current avoided TUOS methodology would need to be amended to include non-locational components, or transmission pricing would need to become LRMC-based.

The trials revealed:

- Considerable disagreement between generation proponents and DNSPs regarding the value that embedded generators were able to contribute.
- For LV connected generators, we found the trailed method (Option 4) resulted in approximately one third of the value of the LNC being from the transmission network. The only network to significantly deviate from this was Ausgrid, where the transmission value was closer to one half of the LNC.
- The value associated with TUOS stemming from non-locational TUOS Charging ranged between approximately 40% (Powercor) and 75% (Ausgrid) of the total TUoS value, meaning that our method results in much higher avoided TUOS values.

Economic modelling was conducted which included sensitivity analysis on the inclusion/exclusion of the non-locational component of the transmission pricing. These results and ensuing implications are covered in Kelly et al. (2016).

Recommendation 7: Determine avoidable transmission LRMC and convert to a price signal as per distribution LNC methodology.

We propose that the LNC calculation should be consistent across both transmission and distribution network.

For this to be implemented it would require TNSPs to calculate and publish their prices and have them based upon LRMC. We note that currently in Australia the price setting methodologies for transmission and distribution are quite different, with only distribution pricing having a firm basis in LRMC. Distribution pricing has only recently changed in response to a push for greater cost reflectivity in network pricing and currently transmission pricing continues to reflect backward looking costs. We note the recent trend in the Australian electricity sector to base network pricing on LRMC and note that there is no inherent difference between transmission and distribution networks that would suggest that transmission and distribution networks should continue to have cost-reflective network pricing (CRNP) methodologies that are different in how they attempt to signal price and cost to consumers.

Due to the difference in CRNP methodologies, introduction of an LNC including avoided transmission value would, if it is to be cost reflective, require review of other parts of transmission pricing and/or avoided TUOS mechanisms. Without such reviews there is likely to be a mismatch in the value a generator may be eligible for and the value received by the DNSP in reduced TUOS charges. For avoidable transmission value to 'pass through' correctly it would require one of more of the following: a review of avoided TUOS methodologies to include non-locational components; a review of the overs and unders mechanism regarding non-locational pricing elements; and/or a review of the transmission CRNP methodology with modifications to make it LRMC-based.

In the interim and in the absence of transmission cost reflective pricing being based on LRMC, we endorse the rule change proposal's stance of "including reduced or avoided transmission costs that would otherwise be passed through to end users." (Hoch & Harris 2015),

7.2 Avoided losses

Local generators reduce the losses in delivering energy from the generator to the customer. Combined losses for the transmission and distribution systems are in the order of 6-10% for urban networks and 10-15% for rural networks (Langham *et al.* 2014).

Energy losses must be credited as a volumetric payment as they are inherently related to power flows rather than capacity. Currently, avoided losses from LG are captured as an (uncalculated) benefit to the electricity retailer; therefore, the payment required to correct this issue is from the retailer to the LG. This is currently done through a voluntary (e.g. NSW)[4] or mandatory (e.g. Victoria)[5] retailer-offered Feed-in-Tariff.

The calculation of the value of losses is **price x volume** as follows:

- The **volume** of losses is calculated as the sum of the percentage of losses (the 'loss factor') for each level of the network upstream of the LG, multiplied by the annual generation of the LG. This should include both avoided distribution *and* transmission losses.

[4] http://www.ipart.nsw.gov.au/Home/Industries/Electricity/Reviews/Retail_Pricing/Solar_feed-in_tariffs_201415/16_Jun_2014_-_Final_Report/Final_Report_-_Solar_feed-in_tariffs_-_The_subsidy-free_value_of_electricity_from_small-scale_solar_PV_units_from_1_July_2014

[5] For renewable energy generators only. http://www.esc.vic.gov.au/Energy/2014-Minimum-Feed-in-Tariff/Final-Decision-Minimum-Feed-in-Tariff-for-2015

- The **price** used should be the energy wholesale value for the relevant time-of-use (peak, shoulder or off-peak) period.

Recommendation 8: As the avoided losses transaction must involve the retailer rather than the DNSP, it is considered that the only option is to **exclude avoided losses from the LNC calculation, and recommend that retailers undertake to offer the above calculated avoided loss value to LG for all exports at a minimum.**

Additional Note

Note that the reduction of losses not only has an energy impact, but also has an equivalent capacity impact on the levels of the network upstream of the LG. This is incorporated as an uplift of the capacity impact of the LG on each upstream level of the network (see Section 5.5). The magnitude of the uplift is defined by the loss factor of at each level of the network in relation to the level of the network where the generator is connected.

7.3 Treatment of LG costs

There are a number of potential cost **increases** as a result of LG connections to, or operation on, the network. These include costs associated with:

- The ability of the network to safely handle levels of fault current which may be increased by nearby presence of LG (commonly referred to as “fault levels”).
- The management of voltage stability, where a very high penetration of LG exists on a part of the network with low demand (e.g. long residential feeders with large amounts of PV and low daytime demand).
- Power flows in the ‘reverse’ direction along feeders or other network elements that were not designed to accommodate this type of flow. For example, protection grading costs.

It is useful to note the status quo situation that applies to generation that exceeds the capacity or power quality parameters of the existing network:

a) Augmentations driven by marginal increases from cumulative effects of smaller generator installations are usually not required to pay for augmentations, as it is difficult for an NSP to attribute the augmentation to any particular generator.

b) If, at certain times of day, generation exceeds the network’s capacity (due to line or feeder impedance) the voltage will rise. Most networks require all generation to have voltage protection settings that will trip the generator (ceasing exports to the grid) if voltage exceeds a certain threshold. This has been known to occur in residential areas with high solar PV penetration and low daytime consumption. This is sometimes considered unfair by some generation proponents as they feel they have been ‘allocated’ capacity when they receive a connection approval from the NSP. It should also be noted that this effective export limitation inherently incentivises technologies that actively manage a generator’s impact on the network, such as batteries and inverters that can provide voltage support, which then allow the generator to continue exporting.

c) Generation proposals that significantly exceed the capacity of the network are usually rejected or required to pay augmentation costs as part of their connection. Where this is infeasible the network will ban further connections.

If an LNC were implemented, we note that the status quo of export limitation would also turn off LNC payments. That is, generators prevented from exporting due to b) or c) above would naturally receive no LNC. However, under the status quo, once capacity his hit there is no impetus to upgrade the network to include bi-directional flow capacity even if this was economically efficient, as parties benefiting from the upgrade are not sharing the costs fairly.

7.3.1 Options considered

There are three possible options to deal with these costs:

1. **Do nothing** and accept the limitations posed on generation as part of the status quo.
2. **Incorporate into avoided LRMC calculation:** compute a LRMC for this cost component, and subtract from the LRMC benefit calculation. This would require some regulator guidance for approval of certain types of network upgrades.
3. **Pioneer scheme:** This would mirror the existing way pioneer schemes are conducted: an LG requiring a new expenditure would pay for the upgrade and be recompensed by subsequent LG connections, which would otherwise be 'free riders' on the costs borne by the initial pioneer.

7.3.2 Discussion

There is a wider societal discussion to be had about whether the cost of adapting our network to the technologies of the future is most appropriately shared by all. It may be argued that requiring a strict user-pays approach confers a significant advantage on incumbent (centralised) generation, as all system users have paid for the development of the current configuration (uni-directional flows). Making any deviation from this traditional network development path on a user pays arrangement has been argued by some proponents to ignore the need for infrastructure to evolve with technological transition.

Conversely, large amounts of new LG is not likely to be beneficial in all areas of the network from the perspective of efficient system operation and cost reduction, and some limit on managing cost of high penetrations will need to be part of the solution.

The way in which costs of bi-directional flows are included in reforms will impact the way that customers experience network limitations. This wider discussion is well beyond the scope of this methodology development. However, we consider it important to select an option that facilitates a transition to a network fit for bi-directional flows and encourages installation of technologies that support this future network (e.g. batteries and smart inverters).

Adopting the "do nothing" or status quo approach effectively applies a ban on export for a particular period of the day and/or a ban on additional generator installations. This, although imperfect, would appear to encourage technology upgrades to manage network voltage and or load/generation shift to times of day that are more useful.

Averaging the cost of network upgrades into an LRMC as per option 2 was the most cost reflective method considered. This approach promotes stability and predictability that are important for investment decisions of local generation proponents. However, in addition to the wider issues raised about how the network transformation should be paid for, this approach would be administratively challenging at this point in time. While the LRMC augmentation costs are commonly considered by DNSPs for poles and wires, they are not routinely calculated for augmentation allowing bi-directional flows.

A pioneer scheme was closest to the networks' existing method for dealing with connection augmentation costs where many potential future customers benefit from the augmentation of customer's connection. However, we found in practise that pioneer schemes are seldom used and that the administration required for potentially multiple pioneer schemes was seen as burdensome by some NSPs.

Recommendation 9: To address costs associated with LG, we recommend:

- As an interim solution acknowledge the status quo situation as a means of managing the problems in the short term and additionally encouraging technologies that manage their behaviour on the grid (Option 1).
- As bi-directional augmentations become necessary and more prevalent, collect data on their marginal cost, frequency and locational distribution to include them in the methodology in an appropriate way (Option 2). If these are routinely included in the LRMC calculations, it is potentially reasonable that they should be subtracted from the LRMC value calculation in future as it applies to a LNC.[6]

Ultimately it is a matter for the AER to determine when bi-directional flow costs represent justifiable expenditure, and to act as an arbiter for this expenditure to be costed and allocated fairly. Further industry discussion on this matter is required.

7.4 Exclusions from LNC payments

This section is largely informed by the economic modelling performed as part of this project: please refer to Kelly et al. (2016) for further detail.

7.4.1 Existing generators

In implementing a reform it is important to consider effects on the marketplace in the present context of the Australian energy market. The National Electricity Forecasting Report (NEFR) reports that for 2016 the generation from rooftop PV alone was 5,648 GWh (Australian Energy Market Operator (AEMO) 2016). There is a large number of generators already contributing to lower network peaks and thus reducing or deferring network augmentation requirements. Implementation of an LNC must consider these generators.

We understand that the impact of existing generation profiles on network augmentation of is already factored into network planning. We also note that a large number of existing local generators are non-dispatchable and are unable to respond to a price incentive.

We recommend that to receive a LNC, a generator must be able to respond to a price signal, either by making:

- a decision to undertake new capital investment, or;
- an operational change.

In the case of existing generators, the decision to invest in the system is already undertaken, and as such an operational change is the only impact that an LNC can have. To work through the implications of an LNC for some examples of existing generator types:

- Cogeneration facilities operating on a daytime peak-lopping profile would likely be influenced by the LNC price signal and change their operating profile to extend generation hours into the evening peak period or operate at higher load during the day.

[6] This is similar to the approach applied for solar in Minnesota, in that costs were acknowledged to play an important role in the fair value setting but could not be calculated now and a calculation methodology determination was deferred until a future update.

- Existing rooftop solar PV generators will have no ability to influence their generation profile to respond to the price signal, that is, unless storage or load shifting technology is procured to adjust the PV export profile.
- Larger generators such as bagasse bioenergy currently generating may or may not change their operation in response to an LNC, depending on the balance of incentives. In many cases they may already be operating at network peak times driven by energy market price signals. This is more likely where network and energy market peak periods align.

7.4.2 New generators under 10kW

Reference to generators under 10kW is primarily focused on non-dispatchable residential rooftop solar PV and should be interpreted as such.

We consider rooftop PV systems relatively unlikely to be incentivised by an LNC, as the additional value of an LNC is less significant than changes in the installed system cost, and the residential market is arguably less influenced by strictly economic factors. In addition, rooftop PV systems are less likely to result in network benefits than commercial systems, as they are non-dispatchable, and more likely to be located in areas with evening peaks.

Where batteries are in place this may change this conclusion to some degree, however further work needs to be done on the influence of an LNC on system sizing/design and dispatch strategy for batteries to better understand the value of offering LNCs to small generators with storage.

Recommendation 10: We recommend that LNC payments should be made to existing generators where this can incentivise behaviour that will reduce network costs. **LNCs should not be paid to existing non-dispatchable generators, or to new generators under 10kW.** More work is required to determine the value of offering LNCs to existing dispatchable generators, depending on the network and generator circumstances.

This recommendation aims to maximise economic benefits to all consumers.

Note that the implementation of an LNC according to generator type or circumstances would break the technological neutrality principle outlined in Section 2.5. This may be warranted to achieve an optimal societal outcome.

7.4.3 Generators without a retailer

We recommend that generation plant that does not have a retailer relationship would need to secure such a relationship to enable the LNC. Without this, a new payment relationship would be required directly between a DNSP and a generator. As DNSPs are not in the business of managing large numbers of payment relationships we found that it was retailers who were best positioned to carry out this function.

Recommendation 11

The LNC should be mediated via a retailer, so generators without a retailer should secure that relationship. The LNC should be structured in such a way as to promote easy retailer pass through, and retailers should be encouraged to implement this pass through.

8 RECOMMENDED METHODOLOGY

The required inputs to the calculation of an LNC are summarised in Table 8, followed by the recommended methodology. The recommendations from the previous sections are summarised in Section 8.1.

Table 8: Required inputs to the calculation of an LNC

INPUT	Already Calculated[1]	Comment
LRMC by network level and customer class	Yes	$/kVA/yr
Transmission Locational charges	Yes	$/kVA/year or $/kVA/Month. Available in Transmission pricing schedules
Average power factor for each network level and customer class	Yes	(No unit)
Average Distribution Loss Factors (DLF) for each network level	Yes	(No unit)
Peak, Shoulder and off-peak times for each customer class	Yes	Times of day and year. It is recommended that peak times are set more narrowly than for consumption tariffs, with a maximum of approx. 500 hours per year in the peak period.
Peaking probabilities	No	Probability that a peak event will occur within each of the identified (peak/shoulder/off-peak) periods
Benefit sharing ratio	No	Ratio of total LRMC benefit that would be used as a basis for the LNC incentive. Remaining LRMC to be a benefit accruing to the networks and consequently their customers.
FUTURE INPUTS		
LRMC of reduced replacement (downsizing & retirement)	No	This should be included in the future to enable value calculation of LNC, but data to enable calculation is currently unavailable
Costs of augmentation enabling a bi-directional network	No	The methodology allows for subtraction of the costs for network upgrades allowing bi-directional electricity flows. As these become more prevalent, their marginal cost, frequency and location distribution needs to be re-examined to include them in the methodology in an appropriate way.
LRMC of Transmission network[2]	Yes	This should be included in the future to accurately reflect transmission network costs through a forward-looking methodology.

Notes: 1) Required for network business operation in existing business activities

Notes: 2) Not currently disclosed by TNSPs nor used as the direct basic for transmission pricing.

The recommended methodology for calculating an LNC is as follows:

Step 1

Calculate LRMC broken down by network level and customer class as per the network's existing LRMC calculation methodology used for tariff setting.

Step 2

Add the LRMC of the transmission network:

As a placeholder for LRMC, ISF used the below calculation as a compromise between the positions of generation proponents and DNSPs in establishing avoidable value.

Use locational and non-locational components of the transmission charges levied on the DNSP

$$LRMC_{Transmission} = locational\ charges * 12 + non - \frac{non\ locational\ charges * 8760}{Average\ power\ factor}$$

Where:

- LRMC is in units of $/kVA/year
- Locational charges are in units of $/kVA/month
- Non locational charges are in units of c/kWh

Step 3

Reduce the LRMC for all levels by the benefit-sharing ratio.

Step 4

Locate the generator in the network by both network level of connection and by customer type. Then, the ratio of the loss factors is calculated for each network level above the generator connection point.

$$LRMC_{LNC} = \sum Base\ LRMC\ \ upstream\ levels \times \frac{DLF_{Generator\ connection\ point}}{DLF_{Upsteam\ level}}$$

Step 5

Convert LRMC $/kVA/yr values to volumetric $/kWh values for each period by multiplying by the probability of peak occurring in that period, and dividing by the hours the period occurs.

$$\frac{\$}{kWh}(peak) = Adjusted\ LRMC \times P_{peak}\ \frac{1}{hours\ in\ peak\ period \times Average\ power\ factor}$$

$$\frac{\$}{kWh}(off\ peak\ ) = Adjusted\ LRMC \times P_{off\ peak}\ \frac{1}{hours\ in\ off\ peak\ period \times Average\ power\ factor}$$

Noting that

$$P_{off\ peak} + P_{peak}\ \ = 1$$

This equation can be adapted to allow for further time periods (e.g., shoulder) through using the same formula and ensuring that the sum of the probability terms P_{peak}, $P_{off\ peak}$, $P_{shoulder}$ etc. is equal to 1.

The calculation method is also available in an accompanying spreadsheet [ISF LNC Calculator.xlsm]

8.1 Summary of recommendations

Recommendation 1: **Use LRMC as the basis of the value calculation for an LNC.**

Recommendation 2: Use the same method to calculate the LRMC for LNC setting as for the tariff setting. When the marginal avoided costs of reduced investment in downsizing or retirement as a result of local generation are better understood by NSPs it should be included in the potential savings signalled via the LNC.

Recommendation 3:. Apply a discounting and benefit-sharing reduction to the LRMC to allow for uncertainty present in LRMC demand forecasts and cost estimates.

Recommendation 4: Assess LRMC based on customer class and network level to delineate parts of the network that particular generators may impact. While there was a range of opinions on how location specific the credit should be, it was determined that the LNC should move towards locational specificity at the same rate that cost reflective consumption tariffs move towards specificity, so that the LNC uses the same LRMC calculations as used for tariff setting.

Recommendation 5: Adjust the LRMC for each network based on generator connection point **to account for the capacity effects as a result of losses**, noting that this adjustment will need to be calculated for generator connection level within each customer class.

Recommendation 6: Allocate tariff value through a *well-targeted* volumetric TOU structure. To provide the right availability incentive the DNSP should choose relatively few hours of the year for the peak period and ensure the peak period selected has a high peak probability.

Recommendation 7: Determine avoidable transmission LRMC value. In converting this to a price signal we propose that this is converted to a targeted volumetric payment, as per the rest of the LNC.

Recommendation 8: Exclude avoided losses from the LNC calculation as this is covered in retailer credit offered for energy exports. Retailers should undertake to offer the avoided loss value to LG for all exports.

Recommendation 9: To manage LG costs on the network:

- As an interim solution, **acknowledge the status quo situation** as a means of managing the problems in the short term and encouraging technologies that manage their behaviour on the grid.
- As bi-directional augmentations become necessary and more prevalent, collect data on their marginal cost, frequency and locational distribution to include them in the methodology in an appropriate way. If these are routinely included in the LRMC calculations, it is potentially reasonable that they should be **subtracted from the LRMC value calculation in future as it applies to a LNC.**

Recommendation 10: We recommend that LNC payments should be made to existing generators where this can incentivise behaviour that will reduce network costs. On these grounds **LNCs should not be paid to existing non-dispatchable generators, or to new**

generators under 10kW. More work is required to determine the value of offering LNCs to existing dispatchable generators, depending on the network and generator circumstances.

Recommendation 11: **The LNC should be mediated via a retailer,** so generators without a retailer should secure that relationship. The LNC should be structured in such a way as to promote easy retailer pass through, and retailers should be encouraged to implement this pass through.

Figure 13: Summary of recommendations

Value calculation

Framework for network value of LG

- **1)** Use LRMC as the value basis for the LNC.
- **2)** Use the same method to calculate LRMC as is used by networks in tariff setting.
  - **2.1)** Include repex value from downsizing or retirement as this becomes better understood.
- **3)** Apply a discounting and benefit sharing factor to the LRMC.

Calculation by location, network level and customer class

- **4)** Locational specificity to match specificity used by networks in consumption tariffs. Use customer class and voltage level as locational proxies for the type of network.
- **5)** Adjust LRMC for the network value of losses and network power factor impacts.

Transmission value

- **7)** Include Transmission LRMC value, signal value through probabilistic tariff structure as per recommendation 6).

Avoided losses

- **8)** Do not include the value of avoided losses, these are included in the energy value.

LG Costs

- **9)** Apply the interim solution of an export gateway.
- As bi-directional augmentation costs become more commonly quantified, subtract these from the LRMC value.

Tariff Creation

Volumetric allocation:

- **6)** Assess the probability of the peak happening in each hour of the year, allocate hours into peak, shoulder, off-peak (and optionally critical peak) periods.
- Choose relatively tight peak periods with high peaking probability.
- Multiply the value set in the previous steps by the peaking probability of each hour in the relevant period.

Generator inclusions and exclusions

- **10)** Exclude existing non-dispatchable generators, and new generators under 10kW from LNC payments (to maximise economic benefits).

Payment settlement

- **11)** The LNC should be mediated via a retailer; generators without a retailer should secure that relationship.

9 CONCLUSION

This work provides a recommendation for an LNC methodology that is strongly aligned with cost-reflective consumption tariff setting methodologies. The inputs required for the LNC methodology are the same, or very similar, to those required for setting consumption tariffs, so the introduction of an LNC should not require undue administrative resources for calculation.

Some of the questions that have arisen during LNC methodology development are of broad interest, and should be debated outside the rather technical discussion of setting an LNC methodology. In particular, the question of how to meet the cost of adapting our networks for a future where the prosumer is the norm, and how those costs should be shared, is a broad societal question that deserves general discussion.

9.1 Additional research needed

This work highlights the following areas where additional research and debate is desirable in order to refine the recommended method:

- Calculating the value of local generation and storage in reducing replacement investment;
- Calculating the network costs associated with increasing DG penetration;
- Discussion of how the above costs of DG should be borne in the context of an evolving electricity network; and
- Refinement of the value setting and benefit-sharing parameters to ensure that the LNC is sufficiently targeted to incentivise generator investment and operational behaviour.

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11 APPENDIX

Table 9: Methodology Comparisons from investigated international precedents

Methodology	Value calculation	Location	Time	Payment structure [Additional values]	Operation	Availability	Cost Reflectivity	Stability	Transparency	Implementation	Neutrality
UK CDCM	Marginal Cost based on 500MW increments	By voltage level	Probabilistic: based on peak periods and estimated generation	Volumetric [Losses]	✓	✗	✓ ✗	✓	✓ ✗	✓	✓ ✗
Connecticut	Declining percentage of DUOS and TUOS	Generator and consumer in same distribution territory	Applies to exports not consumed by customers other sites within billing period	Volumetric	✗	✗	✗	✓	✓	✓	✗
Minnesota	NPV of value of generator over lifetime. 12 months hourly load & generation data	Assumed low voltage (LV) (Solar only)	All	Volumetric, [avoided generation, capacity, ancillary services and environmental benefits]	✗	✗	✓	✓	✓ ✗	✗	✗
ActewAGL	Estimate avoided TUOS	Assume LV (Solar only)	All	Volumetric	✗	✗	✗	✓	✗	✓	✗
Ausnet	Unknown	Assume LV (Solar only)	Summer generation only	Volumetric	✓ ✗	✗	?	✓	✗	✓	✗
Reference service approach[1]	Lowest avoided cost	Very location specific, requires user to be identified			✗	✗	✓	✓	✗	✗	✓ ✗

1 Both Western Australia in the WA Wheeling Method and Transmission pricing guidelines include a methodology based on this approach

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