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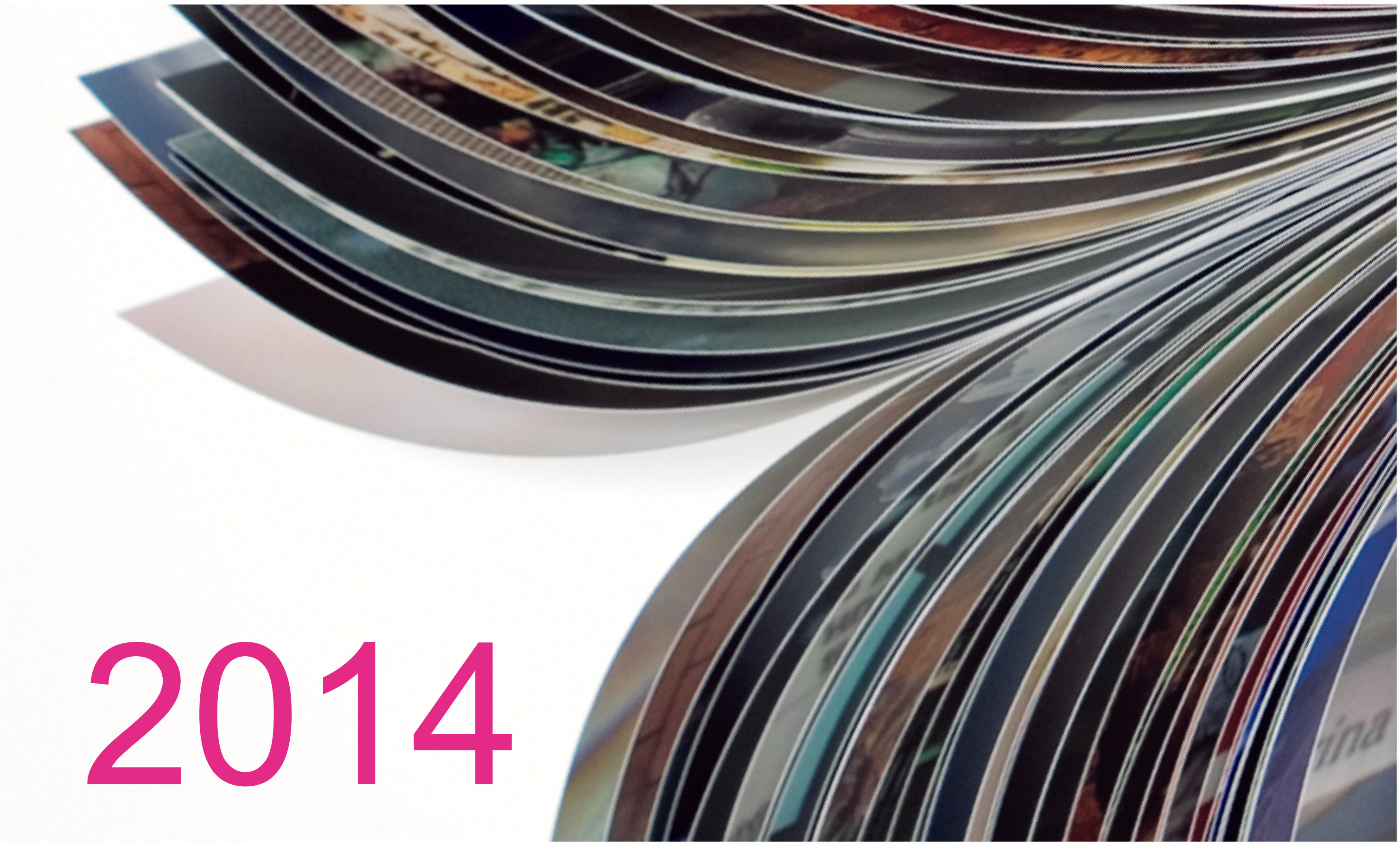
INSTITUTE FOR SUSTAINABLE FUTURES

Institute for Sustainable Futures

CALCULATING THE NETWORK VALUE OF LOCAL GENERATION AND CONSUMPTION

CAP GRANT STAGE 1 REPORT PREPARED FOR TOTAL ENVIRONMENT CENTRE



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ABOUT THE AUTHORS

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GLOSSARY & ABBREVIATIONS

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CDCM	Common Distribution Charging Methodology: Method used in the United Kingdom to calculate the DG credit values
DEC	(Universal) Distributed Energy Credit: Framework whereby *any* DG connected to the distribution network is credited for the network value of its exports, irrespective of a contractual relationship with a local customer
DG	Distributed Generator: Generator less than 30MW embedded within the distribution network
DUoS	Distribution Use of System: Network charge covering the customer use of the distribution network
F-Factor	Term used in United Kingdom CDCM (see above) to assign probabilistic measure to represent the technological availability of each generator type during the peak period
FiT	Feed-in-Tariff
Interval metering	Metering that captures data in half hourly increments
IPART	NSW Independent Pricing and Regulatory Tribunal
ISF	The Institute for Sustainable Futures, University of Technology, Sydney
kVA/MVA	Kilo/Megavolt Ampere
kW/MW	Kilo/Megawatts
kWh/MWh	Kilo/Megawatt hours
LUoS	Local Use of System: Proposed network charge covering the customer use of a smaller 'local' subset of the distribution network
NEM	National Electricity Market
NER	National Electricity Rules
NUoS	Network Use of System: Network charge covering the customer use of the distribution and transmission networks (DUoS + TUoS)
PPA	Power Purchase Agreement
PV	Photovoltaic (solar)
TEC	The Total Environment Centre

TOU	Time of Use: Time-based pricing system commonly comprising peak, shoulder and off-peak periods
TUoS	Transmission Use of System: Network charge covering the customer use of the transmission network
VNM	Virtual Net Metering: a market arrangement where an electricity customer with on-site generation is allowed to assign its 'exported' electricity generation to other site/s by matching generation and consumption on a time of production/use basis

1 INTRODUCTION

The Australian electricity market has witnessed a proliferation of small generators connected within the distribution network over the last five years. This was driven by substantial increases in the costs of electricity and, in the case of solar photovoltaic (PV), government incentives coinciding with reductions in the installed cost. Such generators are commonly referred to as 'local', 'embedded', distributed' or 'decentralised' generators, but for the purposes of this report the term 'distributed generation' (DG) is used. The scale of DG considered for the purposes of this report is generally less than 5 megawatts (MW), but in some cases may be up to 30MW, providing the generation is still connected to the distribution or subtransmission network and the energy is consumed in the local area. In addition to solar PV, examples could also include small wind turbines, cogeneration and trigeneration plants, diesel generators, or gas turbines.

Distributed generation uses only a small part of the electricity transmission and distribution network, as electricity is generated physically close to where it is used. This is because electrons 'exported' into the grid will flow to the nearest site with electricity demand before being consumed. This substantially reduces the distance electricity travels through poles and wires between the generator and the consumer. DG therefore reduces the volume of electricity flowing through the electricity network, which has the potential to deliver the following electricity network or market benefits:

- 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.
- Reduce the need for investment in **network augmentation** in response to peak demand growth.
- Reduce **greenhouse gas emissions**, if the DG source is low or zero carbon. Note that as the carbon intensity of centralised generation is dominated by coal-fired power stations, the reduction in losses also reduces greenhouse gas emissions.

These benefits are not currently valued for DG exporting into the network,[1] resulting in a market failure that inhibits the uptake of DG, reducing potential economic and environmental gains in the efficiency of our electricity production and delivery.

In the current regulatory environment, most of the energy generated by new distributed generation systems must be used on site to be a viable investment. In this case, the DG is effectively reducing load, and gets the benefit of the full retail cost of electricity, which is likely to be in the order of 15-30c/kWh for business customers and 25-35c/kWh for residential customers.[2]

Generation exported into the grid may be eligible for regulated or market driven feed-in-tariffs (FiT), sold on the wholesale spot market, or less commonly, sold to a retailer via a

[1] This is not true for embedded market generators, for which AEMO calculates Marginal Loss Factors (MLFs). This means that generators are recompensed or charged for specific loss factor differences based on location.
[2] Assumes flat tariff rate (not Time of Use). Variations are substantial due to location (network area) and/or consumption amount or load profile.

Power Purchase Agreement (PPA). The current FiT recommended by the regulator, IPART, for residential solar PV connections in NSW is between 6.6 and 11.2 cents per kWh[3] (IPART 2013), compared to a retail cost of between 17 – 30c/kWh, so in most cases the uptake of DG will be restricted to sites with sufficiently large demand to use most generation on site.

There is also a strong desire for the uptake of DG by medium sized entities such as local councils wishing to reduce the cost and improve the environmental sustainability of their own energy supply. These entities are installing or looking to install self-generation, and frequently have multiple sites within a single local distribution area. However, under current regulatory arrangements electricity users cannot supply their own nearby facilities from centrally located DG via the distribution network and pay a cost reflective charge for network use. While not specifically disallowed, there is no mechanism or requirement for the calculation of such a charge, so in effect the DG is expected to export at wholesale energy or FIT rates, and buy back off the grid at nearby sites at full retail rates. This situation has prompted some organisations to investigate or install 'private wire' systems, which while more cost-effective for the organisation, represent a market failure as in most cases it merely duplicates the existing distribution network. The lack of a mechanism to recognise local network use in a cost-reflective manner also improves the relative financial viability of energy storage solutions (designed to maximise "behind the meter" use of locally generated energy), which are predicted to become an increasingly viable future alternative.

Supplying a third party customer within the local area is similarly problematic, as with no recognition of the network benefits of DG the would-be-local purchaser of DG exports is liable for full distribution network charges, even if the sites are next door or on a separate meter within the same building, as commonly occurs in the Sydney CBD. Supplying third party customers has the additional complication of either requiring a retail license or a regulator's exemption to enable such as transaction to occur.

The goals of this report are to:

1) Review the methodologies for valuing the contribution of DG to the electricity network;
2) Examine different allocations of this value to the local generator, the purchaser of DG exports, and the network operator, to see how different stakeholders may be affected; and
3) Identify further work needed to develop a cost reflective methodology, which allocates benefits appropriately to the DG, customers, network operators, and retailers.

The aims of developing an effective method to value DG are to:

- encourage more efficient use of electricity network infrastructure, to reduce price pressure in an environment where network charges make up the single largest component of Australian electricity bills, at between 36 and 57% (AER, 2013a);
- encourage more efficient design and uptake of DG systems;

[3] For benchmark values see IPART (2013a, p.4). According to information on IPART's MyEnergyOffers website, the highest available feed-in-tariff available to a Sydney customer in May 2013 was 8c/kWh. Approximately half of the retailers did not offer a FiT (IPART 2013b).

- establish a fairer representation of network costs and benefits for local generators and consumers;
- facilitate the change towards a more "integrated grid" that delivers consumers the optimal mix of benefits of both centralised grids and decentralised energy production; and
- maintain a revenue stream for electricity networks in an inevitably more decentralised energy future, to protect both network businesses and grid-connected consumers against undesirable economic outcomes resulting from customers disconnecting from the grid or duplicating network infrastructure.

2 HOW CAN DISTRIBUTED GENERATION BE VALUED?

The value of distributed generation can be calculated and assigned to appropriate parties through one of two overarching approaches: Virtual Net Metering (VNM); or the payment of a Distributed Energy Credit (DEC). These are explained below:

1) **Virtual Net Metering (VNM)** refers to a market arrangement where an electricity customer with on-site generation is allowed to assign its 'exported' electricity generation to other site/s. The other site/s may be owned by the generator themselves (self-generation) or by other electricity customers.[4] Virtual Net Metering may offer a means by which potential DG owners can supply themselves across multiple sites, or a local generator can supply a local customer, with the market arrangements more accurately reflecting the costs of network services supplied (see below for further explanation). The term 'virtual' is used to describe this sort of metering arrangement to distinguish from net metering at a single site, which has most commonly been applied in situations where small PV or wind systems are installed. In net metering, charges or credits are based on the difference between what is imported and what is exported from the site in a particular time period.[5] In Virtual Net Metering the billing reconciliation happens with reference to the DG export to the network, and the customer/s import from the network. VNM requires a mechanism to charge for the network services being used, or to value the portion of network savings which are being delivered. This can be achieved in a number of ways, such as: the establishment of a "wheeling charge" that allows DG to pay for local use of the network only; the calculation of a lower network charge for customers purchasing power within a VNM arrangement; or the payment of a "VNM credit" to the DG that reflects the network savings.

2) The establishment of a **universal Distributed Energy Credit (DEC)**, credited to the DG simply because it is embedded in the distribution network, regardless of whether a local customer is identified for the electricity. This reflects the fact that most DG (generally small to medium in scale) will only use one level of the electricity distribution network, and depending on the timing and nature of the generation, may reduce network augmentation costs by lowering peak demand above the level of network connection. Flat rate feed in tariffs could be considered as a universal Distributed Energy Credit, but

[4] Virtual net metering has also been referred to as 'remote net metering', 'neighbourhood or group net metering'.

[5] On site net metering may be done on either a time of use basis, so that the user is charged for what they import minus what they exported during the same period, and surplus electricity credited as exports (which may attract zero payment in some cases). Alternatively, net metering may be done on a cumulative basis, in which the time period is a day or a month. It is assumed in this report that any net metering being discussed in this report would be time of use based, with hourly or half hourly netting off.

have generally been designed as renewable energy industry support mechanisms (subsidies), and have not been designed to reflect cost savings in the electricity network.

The primary difference between Virtual Net Metering and a universal Distributed Energy Credit is that with a universal DEC, the DG does not need have a relationship to the customer for the electricity. This removes considerable complexity, and may fit more easily into current market arrangements, but it may be more difficult to justify that DG is balancing a local load and therefore delivering all of the value for which it is being rewarded. (Although if a DEC was combined with a generation cap within the given local distribution zone to ensure no upstream exports occur, this could nullify this concern.) It may also be more difficult to achieve as a regulatory amendment due to the greater reach of a universal DEC.

There may be technical solutions to ensure that the universal DEC is only paid when exports are used within the local substation or distribution feeder area.[6] These could include things such as remote disconnection of PV of other DG by the network operator, or additional metering to ensure that the DEC only gets credited in full when there is no export from upstream from the distribution network level.

It may also be possible to combine the VNM and universal DEC approaches using scale eligibility, such as by limiting the DEC to midscale (say, greater than 50 kW) systems.

Both VNM and a universal DEC will require a methodology to determine the value of the network services offered, and according to the principles established for this work, it should be cost reflective and should not rely on cross-subsidisation. As DG offers network benefits, it should be possible to value DG in a way that is reflective of the benefit or reduced burden on the system.

Four alternative methodologies to calculate and distribute the value of DG are outlined in this report, and the following examined:

- Whether they can be used in both VNM and universal DEC;
- How they affect potential market pathways; and
- An indicative calculation of values to participants using the different methods.

It should be noted that the advantages and disadvantages of VNM relative to DEC may be independent of the methodology used to value the network benefit.

The effect of energy cost savings or losses was specifically outside the scope of this work in the analysis of stakeholder cost benefit. Energy transactions will have considerable impact on the effects of DG on different stakeholders, so should be considered for inclusion in further analysis as part of Stage 2. Note that energy transactions between stakeholders will vary greatly according to the alternative market pathways outlined in section 4.

[6] The relevant network boundary would be defined according to the level of reduced network costs recognised in the calculation, but may be the zone substation, distribution substation or distribution feeder area.

2.1 TERMINOLOGY

There are many terminology options for the charge or credit to be used when valuing DG. In order to emphasise that valuing DG is intended to increase the cost reflectiveness of network charges, ISF proposes two key complementary terms:

1. A **"Local Use of System (LUoS)" charge**: LUoS is intended to be the appropriate charge for a customer purchasing 'local' DG from the nearby area, which reflects use of a smaller portion of the distribution and transmission systems to transmit energy from the nearby generator. The term LUoS was chosen to harmonise with current network charging terminology, which is divided into Transmission Use of System (TUoS) and Distribution Use of System (DUoS) charges, which are together referred to as Network Use of System (NUoS) charges.
2. A **Virtual Net Metering (VNM) Credit**: This term refers to the costs that are avoided by electricity network businesses due to the presence of DG in the system. It reflects both reduced losses, and avoided augmentation on the higher levels of the network that are not used to transmit energy from the local generator to the nearby customer.

LUoS is calculated as the amount of NUoS remaining after accounting for the reduced costs associated with DG (the VNM Credit). The relationship between these elements is represented by the following equation:

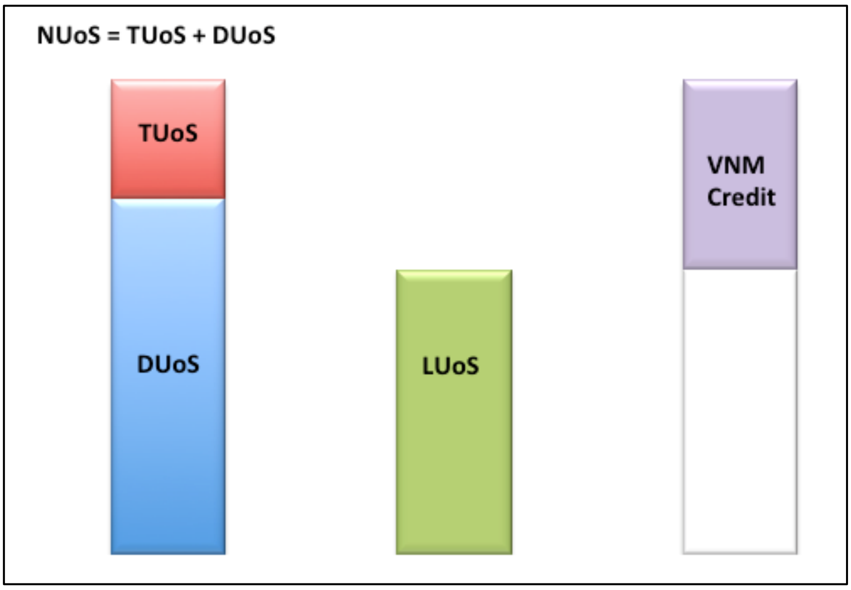
$$\text{LUoS} = \text{NUoS} - \text{VNM credit}$$

OR

$$\text{NUoS} = \text{LUoS} + \text{VNM credit}$$

Figure 1 below shows LUoS and the VNM credit, as they could compare to NUoS, TUoS and DUoS. The size of LUoS and the corresponding VNM Credit would vary according to where in the distribution network the DG (and potentially their 'contractually connected' customer/s in a VNM arrangement) is located.

Figure 1: NUoS, TUoS, DUoS, LUoS and VNM credit



The methodologies in Section 3.2 detail alternative ways to calculate a VNM credit, while the market transaction pathways explained in Section 4 show how this value could be credited to different stakeholders. Depending on the market transaction pathway chosen (who the credit accrues to), the value of local generation and consumption would either be considered to be a:

1. **LUoS charge** if applied:
   a. As a reduced network charge to the local customer purchasing the DG (i.e. the customer is charged LUoS instead of NUOS)[7], or
   b. As a "wheeling charge" paid by the DG operator to the network for the transfer of exports;[8] or a
2. **Or a VNM Credit** if applied:
   a. As a credit to the local customer[9], or
   b. As a credit to the local generator,[10] which could then be passed onto the consumer in the form of a reduced energy price.

Note that the term VNM Credit is appropriate if applied within a VNM arrangement, but if applied universally to all DG, the term Distributed Energy Credit (DEC) would be more appropriate. **For simplicity, this report generally just uses the term "VNM Credit" to refer to the calculation of either the credit calculation, even though it may be applicable as a DEC.**

[7] See model c) in Figure 13 (Section 4) for diagram.
[8] In the wheeling charge scenario the purchasing customer would not pay network charges on the locally generated energy as the network would receive its income from the DG operator. See model d) in Figure 13 (Section 4) for diagram.
[9] See model b) in Figure 13 (Section 4) for diagram.
[10] See model a) in Figure 13 (Section 4) for diagram.

3 METHODOLOGICAL APPROACHES

3.1 INTERNATIONAL SCOPING

A brief scoping of international approaches to charging for network usage by local generators and local customers was undertaken to determine if viable precedents can be drawn upon. The results are summarised below for the United States, Continental Europe and the United Kingdom.

United States: A total of 47 states in the US have 'net metering' mechanisms in place for the promotion of renewable energy technologies (Poullikkas at al 2013), however only around 13 states offer 'virtual net metering' where multiple consumer meters can be netted off against the local generator's production (eligibility criteria apply; ISF 2013). In the case of both net metering and virtual net metering, almost all US jurisdictions[11] deal with the charging for usage of the public electricity grid to transport electricity between local generators and nearby consumers very simplistically, and in a non-cost-reflective fashion. As noted by Poullikkas at al (2013), distributed generation exports are generally credited to the generator at either the full retail rate (e.g. Maryland, Maine, Vermont, Illinois) or the wholesale electricity rate (e.g. California for virtual net metering). Neither case is considered cost reflective, as:

- in the case where generators are credited the full retail rate for exports, this is equivalent to "free" use of the network to transport DG exports to nearby customers and represents an embedded subsidy to distributed generators; and
- in the case where only the value of energy of exports is credited to the generator, this ignores the benefits that the DG provides to the network. This is the current situation in Australia, and represents a market failure that prevents an optimal level of DG being adopted.

An exception to crediting DG exports is Connecticut, where the generator exporting electricity (within a VNM arrangement) is credited at the wholesale energy cost *plus* 40%[12] of relevant transmission and distribution charges (NUoS). Using the terminology from Section 2.1, this represents a 'VNM Credit' of 40% of NUoS (leaving a 'LUoS charge' of 60% of NUoS).

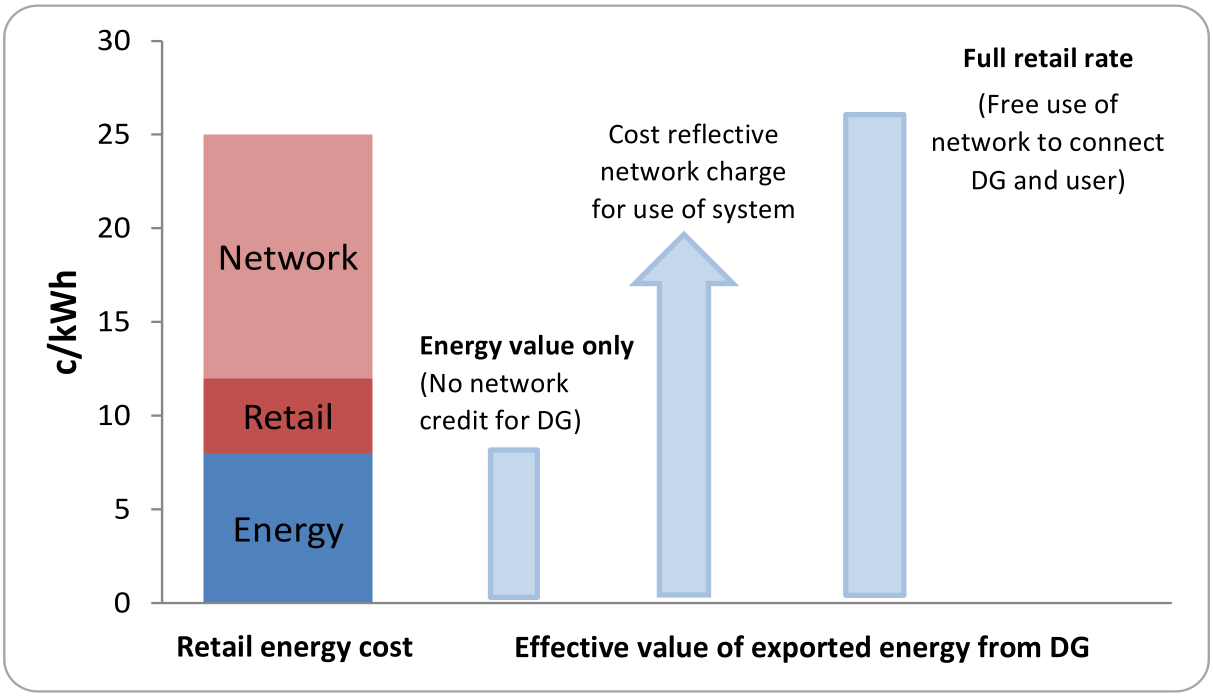
ISF contacted the Connecticut Public Utilities Regulatory Authority who confirmed that the rationale for partial crediting of network value is the same as that driving this Australian review, and the value was reached as a compromise between those advocating for case 1 (free use of network) and case 2 (no credit for network benefit) above. There was no scientific method for arriving at this value, however the Authority believed that generators

[11] Based on a high level review. Review of all primary sources was not possible within the bounds of this project.

[12] This is in fact applied as 80% of NUoS in the first year, 60% of NUoS in the second year, and 40% of NUoS in each year thereafter. However, this initially higher credit for exports appears to be merely be an incentive in the earlier years.

receiving a VNM Credit of 40% of NUoS was roughly cost reflective when considering avoided system augmentation from DG (Quinlan, pers comm, 2013).

Figure 2: US Net Metering and Virtual Net Metering Schemes – value of DG electricity exports to the grid



Note: the breakdown of costs on the vertical axis roughly reflect Australian utility costs rather than US costs

Continental Europe other than Germany: Some limited reference to "partial exemption" of network charges was found in Denmark, and consideration of an export "grid use charge" and an impending "review of network costs" in Cyprus (Poullikkas, et al 2013 and pers. comm., 2014), however further searching failed to reveal sufficiently detailed information available in English. These lines of enquiry were not further pursued.

Germany: Since 2012 Germany has permitted 'direct marketing' as a market based alternative to the feed-in-tariff, whereby renewable energy generators (or virtual aggregations of smaller generators) can sell directly to the electricity consumer. In order to provide incentives for lower network utilisation, the Federal Government's Electricity Tax – the *Stromsteuergesetz* – was made exempt to customers purchasing electricity from a local distributed generator (Federal Government of Germany, 2012). To receive the tax exemption the customer must purchase electricity from a generator that:

- is no greater than 2MW in size;
- is located within a 4.5km radius of the consumer[13]

[13] Whilst the wording of the amended tax legislation specified a 'regional relationship' between the generator and customer, the 4.5km radius has come in later through legal interpretation and precedent.

This sort of arrangement is known as 'local direct marketing'. The avoided tax equates to a EU2.05c/kWh (AU3.2c/kWh) discount on electricity consumed, which is split between the generator, consumer and electricity broker on negotiation.

According to direct marketing broker Next Kraftwerke, an arrangement between a 500kW distributed generator and a local customer could result in an annual avoided electricity tax of €70,000 (AUD$110,000), to be split between the customer, generator and broker. [14]

Evidence must be provided to show that electricity is consumed at the same time as the generation. As part of Next Kraftwerke's contractual arrangements, the customer and generator both must pay for costs incurred from load mismatches:

- If there is less than expected generation the generator must purchase the deficit units through the broker on the market; and
- If there is less than expected customer demand the customer must pay for surplus generated units (Next Kraftwerke, 2014).

Current data suggests that since 2012 approximately 190 new or existing generators have established direct marketing arrangements with local customers (Netztransparenz.de, 2014). According to Wasserman (2013), this relatively slow take-up in local direct marketing is perhaps due to the transaction costs associated with finding a local customer with an appropriate load, and also due to the existing feed-in-tariff being a more economic option for smaller generators.

United Kingdom: The United Kingdom has a Common Distribution Charging Methodology (CDCM) model, which offered the only available comprehensive methodological precedent to examine DG network charging. The UK uses a distributed generation "value calculation" according to value of avoided losses plus the long-term value in avoiding future augmentation. Broadly speaking, the authors consider losses and avoided augmentation to be the most defensible and widely cited components quantifying DG's contribution to the network. Reduced losses and avoided augmentation are used as the basis for calculating network value in all of the methods shown in Section 3.2.

The UK's CDCM methodology provides a robust (although highly complicated) means of calculating and assigning a credit for DG exports. However, it is important to note that the UK approach applies to ALL DG exports, and so takes a Distributed Energy Credit approach rather than a Virtual Net Metering approach. Therefore there is no contractual link between the DG and the customer. The approach assumes that regardless of any arrangement being in place between the generator and the customer (via a retailer or otherwise), electricity will be used locally. This is based on the principles of physics, rather than market logic (OFGEM, 2014). It should be noted that this does not address situations where there is insufficient demand downstream from the DG connection, leading to reverse electron flows,

[14] This figure is based on a generator with a 78% capacity factor, and assumes there are no load mismatches (and therefore each unit avoids the tax).

which may or may not impose a network cost. There are of course technical options to avoid this situation, but it is not clear whether the DEC relies on these being in place.

The advantage is that the universal DEC approach removes need for any contractual arrangement between DG and customer, or for the net metering arrangements to be undertaken by the retailer or any other party, with attendant savings in operational and software costs.

We have incorporated Australian data into an adapted version of the UK method as one methodology considered in this study, and have also used core elements from the UK approach to establish two alternative LUoS charge and VNM credit calculation methodologies. This will be further discussed below.

3.2 POTENTIAL CALCULATION METHODOLOGIES

3.2.1 Overview of methodologies

Four methods of calculating the LUoS and VNM credit have been characterised, and an initial comparison made of the results. The four methodologies are:

1. **Volumetric (the UK method)** – annualised system average incremental capacity costs (in $/kW/yr) are calculated for each network level, and then transformed into volumetric values (c/kWh) for each Time Of Use (TOU) period (peak, shoulder and off peak) according to the probability of the system peak occurring during each period. Volumetric values are then multiplied by an "F-Factor" that represents the security of supply provided by a given type of DG. This method credits all DG exports on a volumetric basis, with no capacity payment component. In the UK, $/kW/yr capacity costs are the "Modern Equivalent Asset Value", which represents the cost to build a kW of capacity if it was built today. As equivalent Australian figures are not readily available, estimated (backward looking) system average Long Run Average Cost is used.
2. **Existing Tariff –** rather than starting with a 'ground up' costing of incremental capacity like the UK method, this approach uses the actual existing, published tariff rates of either the generator or the consumer, providing it is a *TOU tariff with a capacity charge* (as this was considered to be the most cost-reflective of existing standard tariff types).[15] This method treats DG exports as a negative load on the system, crediting exports at the network's own defined import rate, but scaled down according to the level of system usage (so that the local generator 'pays' full costs for the level of connection and below, as per method #1). This method includes a capacity payment based on the lowest level of measured

[15] The authors considered this tariff type to be the most cost-reflective of existing standard tariff types. The detail of whether generator or consumer tariff type is used would need to be decided during Stage 2 of this project should this method be pursued. ISF's accompanying model uses the generator's tariff class.

generator output during peak periods on a number of key peak days, as well as a TOU volumetric payment.[16]

3. **Capacity Payment –** uses the same annualised system average incremental capacity costs for each network level (as per method #1), but allocates this credit purely as a capacity payment, and does not include any volumetric component. The capacity payment rate is multiplied by the lowest level of measured generator output during peak periods on a number of key peak days, as per method #2.
4. **Locational constraint –** Functions as a capacity payment in the same way as method #3, however, only credits generators where there is an impending constraint within the network planning horizon (around 5-10 years). Thus a custom network augmentation value is required to be entered for any given DG connection location. This will generally be a higher value than the 'system average' values in method #3, but will be offered in much a smaller number of locations.

Two key points should be noted on the above methodologies:

- **Losses:** all four methodologies calculate the credit for losses in the same way, by multiplying the sum of % losses per network levels upstream of the DG by the energy wholesale value for the relevant period. These are credited as a volumetric payment as they are inherently related to electron flows rather than capacity.
- **Payment according to level of DG connection**: two common features, based on principles established in the UK method, apply to all but the locational approach. Firstly, network costs (however calculated) are allocated to each level of the network hierarchy (see 3.2.2). Secondly, DG is credited according to its location within the network, by crediting the network costs associated with levels higher up the transmission/distribution system. This is illustrated in Table 3 below: a zero is attributed to each level of the system that is used (and hence 'paid for') by a given generator situation (the pink cells), while a 1 is attributed to each unused level of the system that is 'credited' to the generator (the green cells).

There are also a number of caveats:

- Any network augmentation required to connect a particular DG is external to the calculations of network value, and is met by the generator itself.
- Reverse flows, where DG results in export upstream from a network level, have not been considered in this report, and should be discussed as part of Stage 2 of the project. A generation cap within a given local distribution zone may be a way to control this issue in a DEC arrangement, while a VNM arrangement is likely to self-regulate in that it will only be profitable to generate where matching local demand is present.

[16] Capacity charges are calculated by different networks according to different criteria, however the general principle would be that this incentivises firm supply from the DG at the times required by the local network.

Table 1: Summary table of methodology attributes

Attribute	Volumetric (UK method)	Existing Tariff	Capacity Payment	Locational Constraint
Avoided Augmentation	System average	System average	System average	Locational
Avoided losses	Yes	Yes	Yes	Yes
DG credited with incremental network supply costs	Above the level of DG connection	Above the level of DG connection	Above the level of DG connection	Only in network areas with impending constraints
Credited on volumetric basis	Losses, augmentation	Losses, plus volumetric rate as per existing TOU tariff	Losses	Losses
Credited on capacity basis	None	Capacity charge rate as per existing TOU tariff	Augmentation	Augmentation
Capacity risk management	Probabilistic 'F-Factor' defining technology availability	Purchasing customer pays full capacity charge for net kVA requirement after DG	Network credit solely capacity based	Network credit solely capacity based

The F-Factor used in the Volumetric (UK) Method is a probabilistic measure that aims to represent the technological availability of each generator type during the peak period. This is how the network covers the capacity risk associated with the generator being unavailable during peak periods. Table 2 shows the *preliminary* F-Factors used on this by technology and network area. The F-factor used for Solar PV is very low in the Essential Energy service territory as the peak times are from 7am to 9am and from 6pm to 8pm, which does not coincide with good solar radiation. The solar PV F-Factor for Ausgrid is higher as the afternoon peak period runs from 2pm to 8pm.

As trigeneration can be turned on at the discretion of the operator, an F-Factor of 65%[17] has been used for both network areas network location. This is based on similar UK figures for gas engines with two generator sets (4MW comprising 2 x 2MW engines). A comprehensive examination of F-Factors for each technology was undertaken in the UK, which is beyond the scope of Stage 1 of this work. Thus the values presented in Table 2 below should be

[17] Note that this factor appears lower than may be expected for a dispatchable generator.

considered indicative only, and standard factors would likely need to be agreed upon between technology providers and network businesses (this discussion could be initiated during Stage 2 of the project if this method is preferred). The F-Factors have a very great impact on the calculated VNM credit for each technology.

Table 2: Preliminary F-Factor values by generation type and service area

Generator Type	Essential (7-9am, 6-8pm)	Ausgrid (2-8pm)
Trigeneration	65%	65%
Solar PV	3%*	20%

* Low value due to Essential Energy peak period of 7-9am and 6-8pm correlating poorly with PV production. The UK system does not include an F-Factor value for Solar PV, suggesting that no credit is granted to this technology. This may be because network peak times are more likely to be winter evenings (at high latitude) when no PV generation occurs.

3.2.2 The importance of network location in determining LUoS and VNM Credit

With the exception of the locational approach, a common feature across all methodologies is that the initial starting point for the calculation of the VNM Credit depends on where the distributed generator connects to the network. As a result, the further 'downstream' the generator connects, the greater the value of their VNM credit. This is shown in Figure 3, below.

Figure 3: VNM Credit – percentage of NUoS received by network level (AER data for Essential Energy)

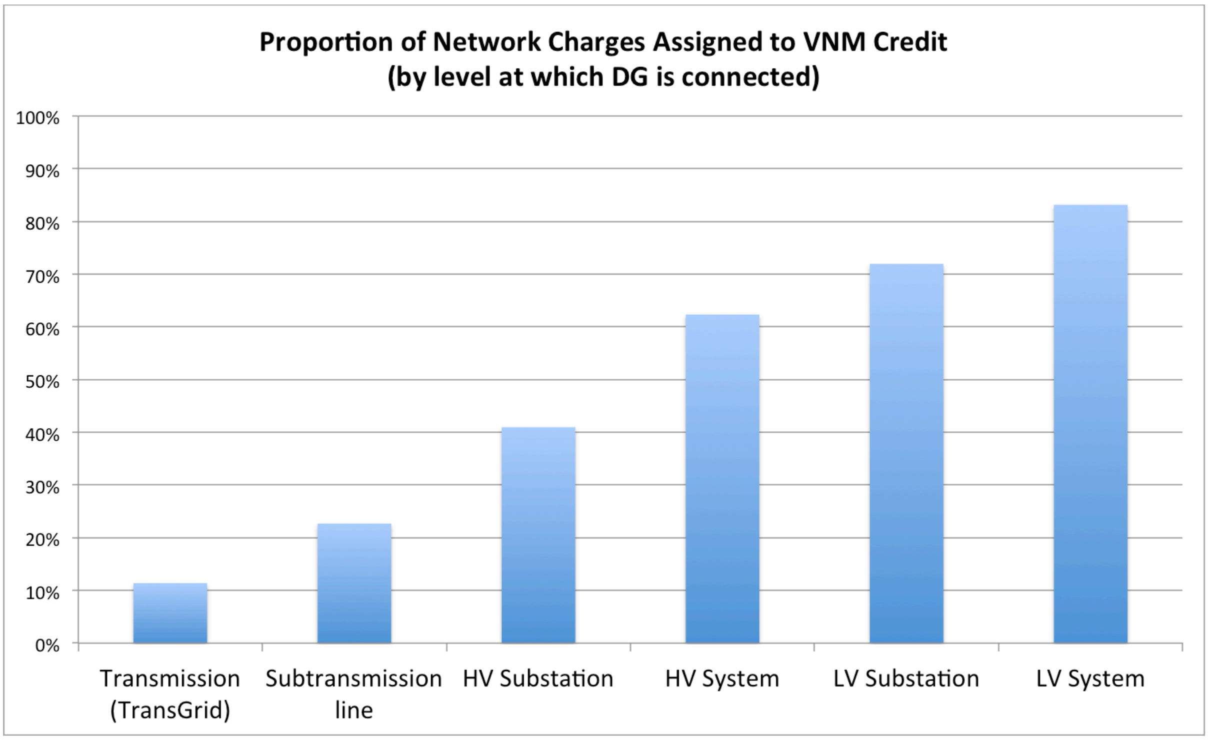


Table 3: Use of System elements according to (DG) generator situation

Generator Situation	Transmission (TransGrid)	Sub-transmission line	HV Substation	HV System	LV Substation	LV System	System-Fixed	Non-System fixed
Co-Located (Same site)	1	1	1	1	1	1	0	0
LV System Connected	1	1	1	1	1	0	0	0
LV Substation Connected	1	1	1	1	0	0	0	0
HV System Connected	1	1	1	0	0	0	0	0
HV Substation Connected	1	1	0	0	0	0	0	0
Sub-Transmission Connected	1	0	0	0	0	0	0	0

An example from Figure 3 (based on Essential Energy data), is that a DG connected at the LV substation would be credited 72% of total adjusted network costs,[18] however those are calculated. The 72% is the sum of the percentage allocation at all higher levels, namely Transmission, Subtransmission, HV Substation, and HV system.

The division of network costs by network level is calculated from the annualised capital asset values of each asset level, based on the network service providers capital works applications for the 2009-2014 AER determination (Country Energy PTRM Forecast Revenue 2009-10, Energy Australia PTRM Forecast Revenue 2009-10, Transgrid Annual Report 2013). The resulting percentages for Ausgrid and Essential Energy network service areas are contained in Figure 4 and Figure 5 below.

Note that in both network areas less than a quarter of network costs are associated with the low voltage component of the network. This is where a majority of DG generators would connect to the network, so there appears to be strong potential for avoiding network charges by installing DG, subject to reliable operation during peak periods.

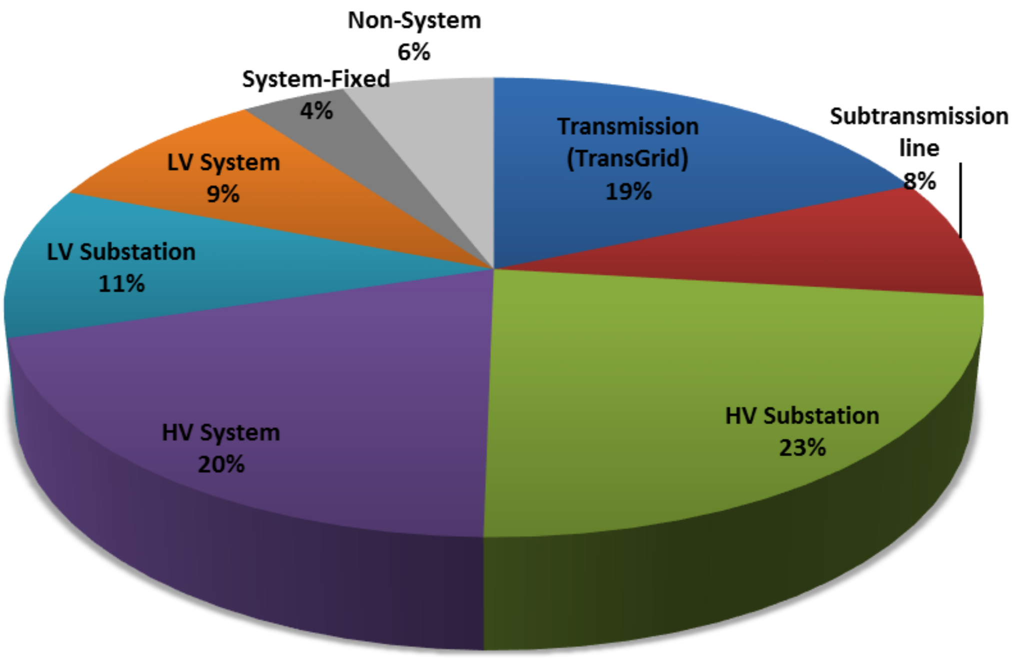
Table 3 shows how the different network costs are included in the VNM credit for generators connected at different parts of the system. For example, a co-located generator who is at the same site as the customer gets all the calculated costs except for the fixed costs (the last two columns at the right). Note that the fixed costs calculated for Essential Energy are substantial and would need to be worked through in Stage 2 of the project. Table 4 identifies the typical network level for connection of various forms of DG.

[18] Depending on the methodology, the adjustments take account of things like generator availability or how likely the peak is to occur in the relevant period.

Table 4: Distributed Generator Connections by network level

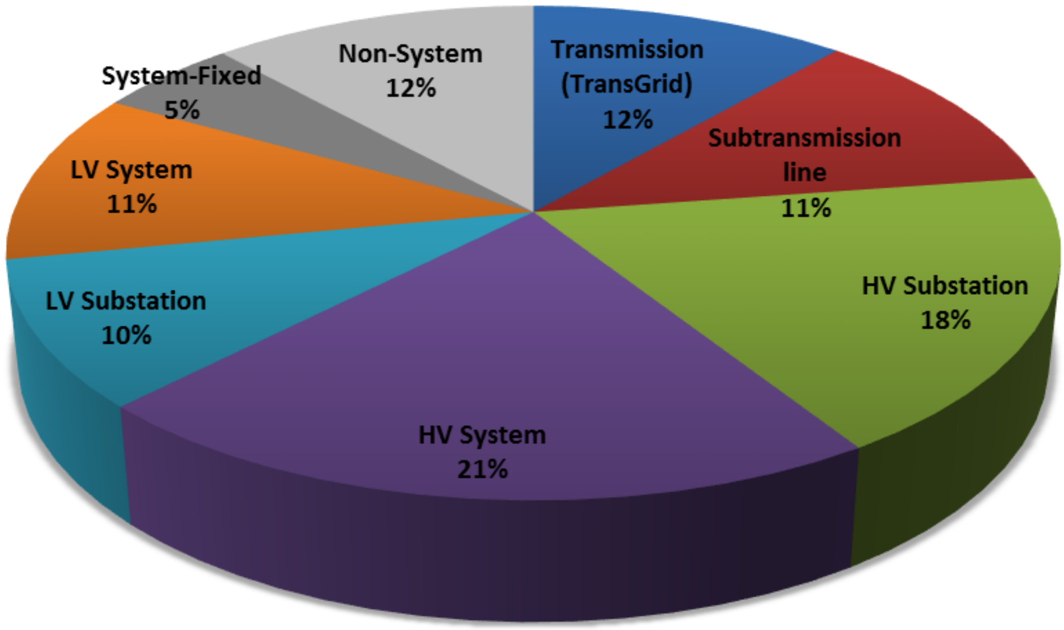
Network level category	Description	Typical DG connections
LV System	Low voltage lines and cables	Residential, small business and some large business customers
LV substation	Distribution substations	Some large business customers, stand-alone DG or high capacity DG i.e. trigeneration
HV system	HV lines and cables between zone and distribution substation level	Limited to some very large business customers/large stand-alone DG
HV substation	Zone substations	DG connections unlikely
Subtransmission line	Lines between Zone substation and bulk supply points	DG connections unlikely
Transmission (TransGrid)	Above Bulk Supply Points	N/A

Figure 4: Breakdown of Network Charges (NUOS) by Network Segment – AusGrid



Note: Based on 2009-14 regulatory determination data from Energy Australia (2009)

Figure 5: Breakdown of Network Charges (NUOS) by Network Segment – Essential Energy

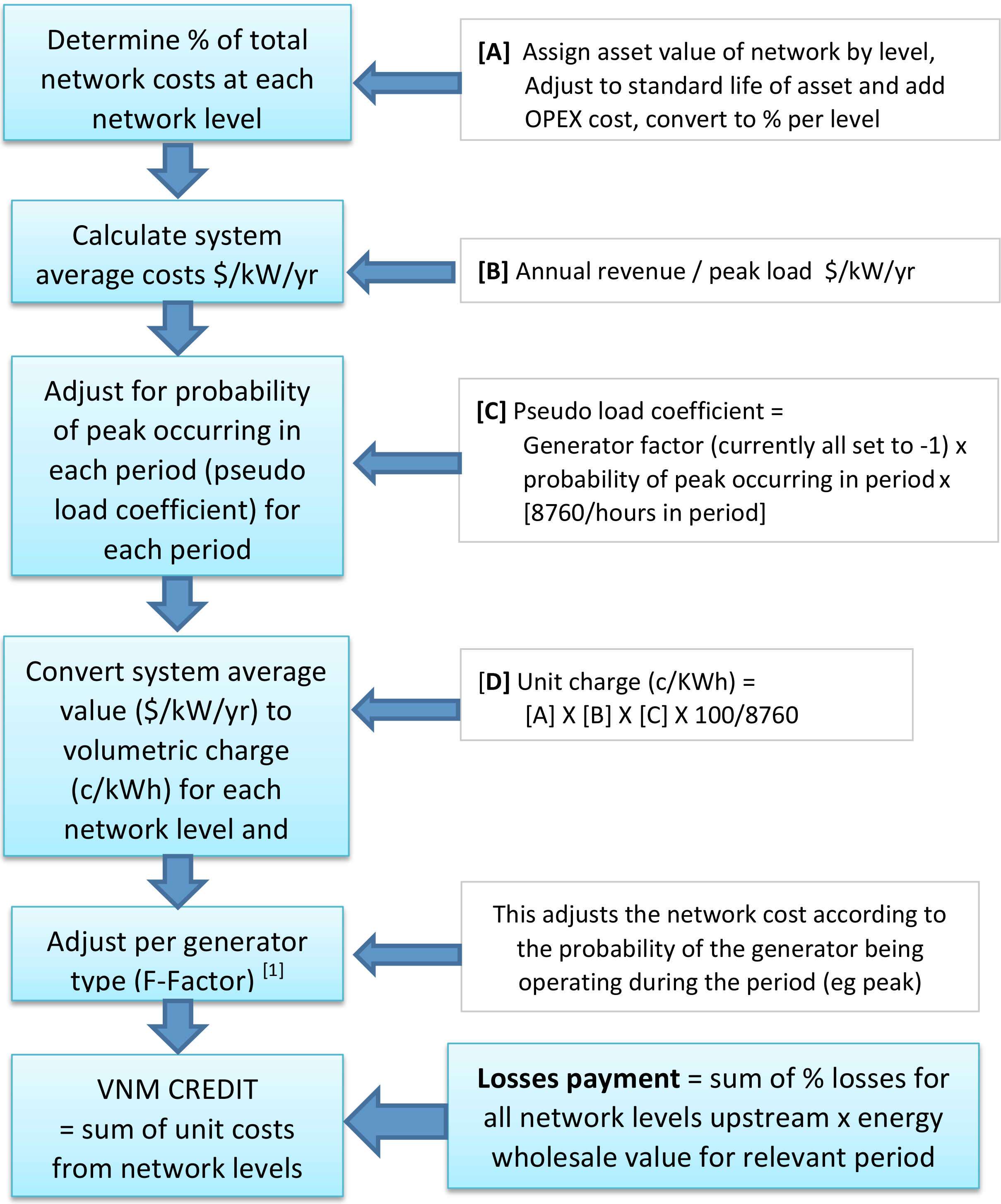


Note: Based on 2009-14 regulatory determination data from Country Energy (2009)

3.2.3 Methodological approaches: step-by-step

The four methods to calculate the VNM Credit (and thereby LUoS) are summarised in Figure 6 to Figure 9. More information on the data sources used as inputs is given in Appendix 1.

Figure 6: Volumetric (UK method) VNM Credit calculation



Note: Probability of peak occurring in period and generator factor is from UK data

Figure 7: Existing Tariff Method VNM Credit calculation

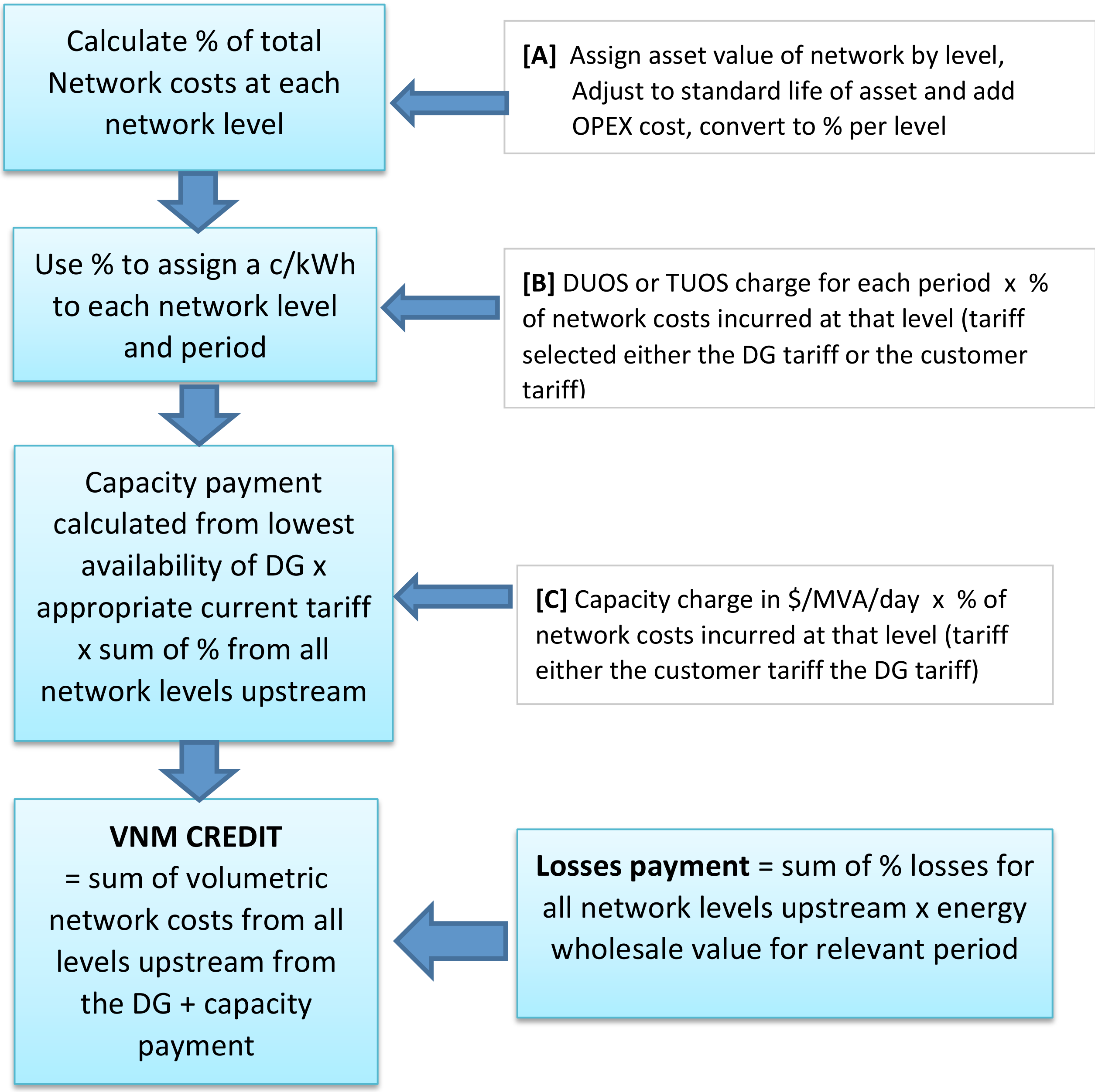


Figure 8: Capacity payment calculation of VNM Credit

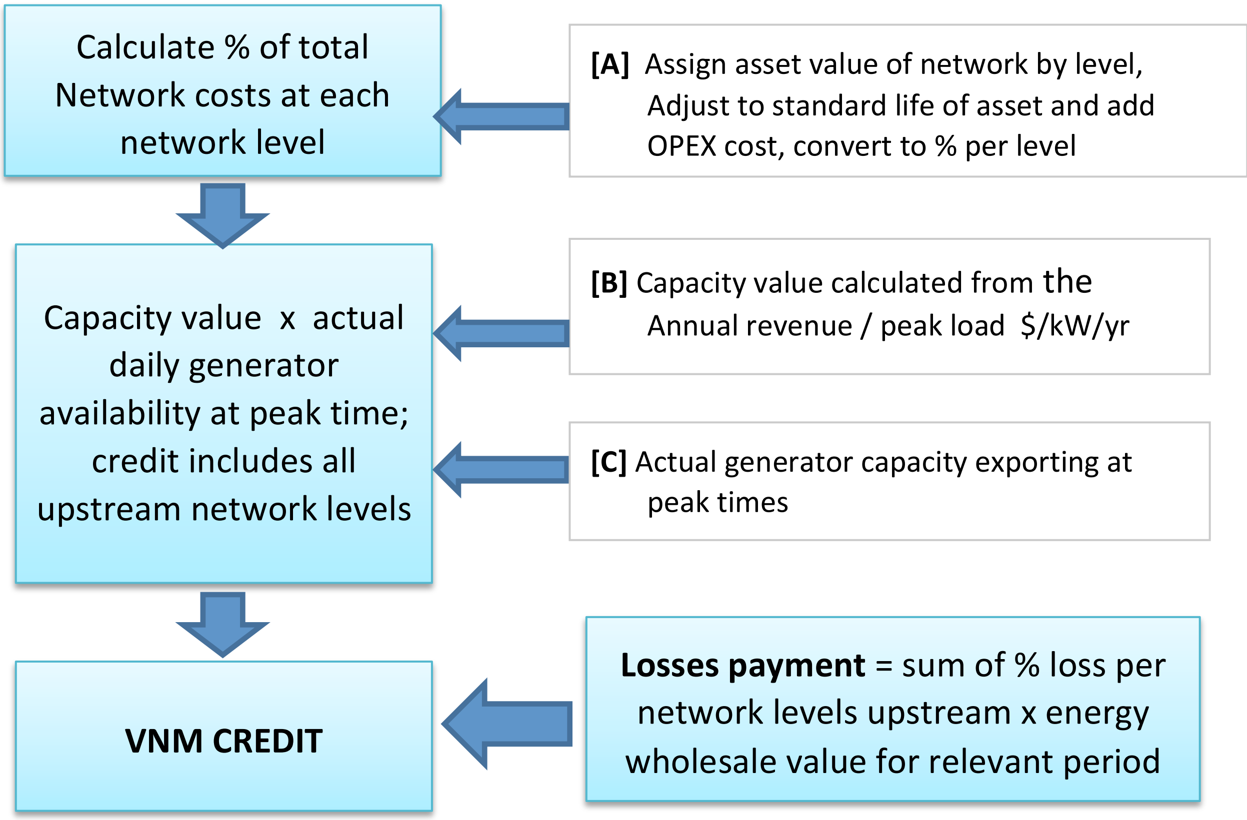
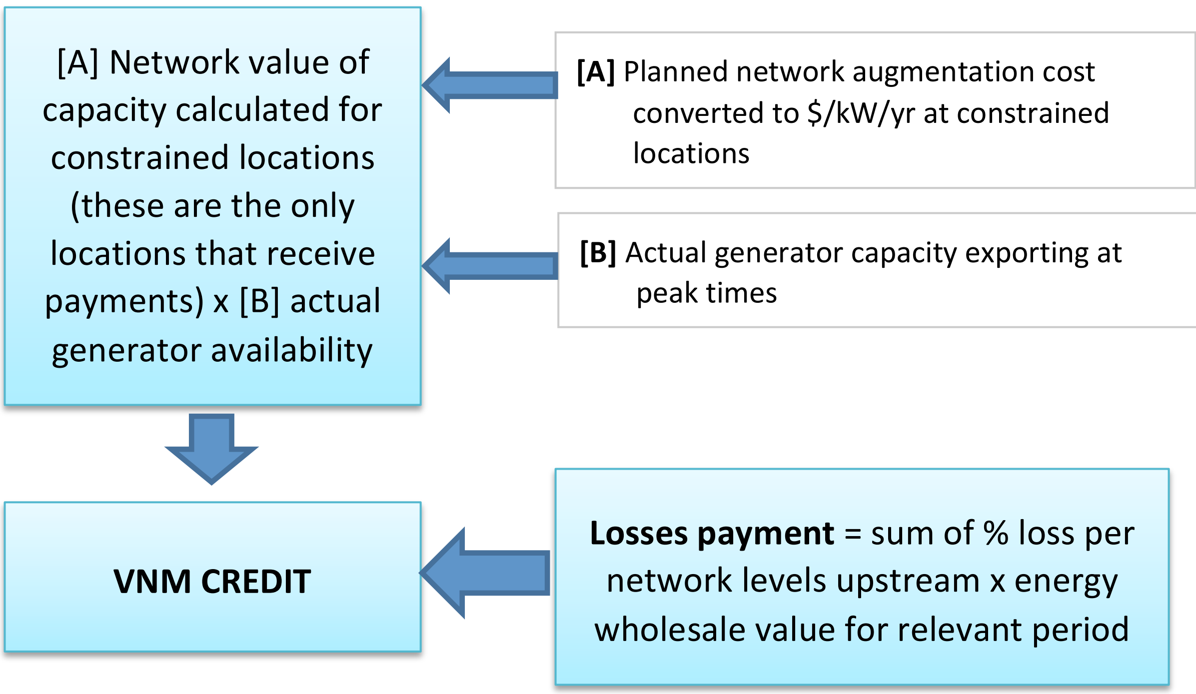


Figure 9: Locational Capacity payment calculation of LUoS



3.2.4 Methodological approaches: worked examples

Volumetric TOU Method

Working through an example of the calculation shown in Figure 6, we will trace the peak VNM Credit export rate for trigeneration in the Ausgrid area using the Volumetric TOU method. This rate is 7.1 c/kWh, as shown in Table 5. Firstly, take the total Ausgrid Long Run Average Cost of network as $363/kW/yr including capital plus operating costs. There is a 90% probability of the system peak occurring during the peak period (which occurs 1506 hours in the year, as the period is set from is 2-8pm on working weekdays). The annualised network cost then converts to a peak period c/kWh rate of:

- $363/kW/yr x 90% x 24hrs/day x (365 days/yr / 1506 hrs/yr) x 100/8760 = 21.7c/kWh

If the generator is connected at the HV system level, this means that 50% of the system costs are used, and the other 50% is credited, so value drops by half:

- 21.7c/kWh x 50% = 10.8c/kWh.

The trigeneration F-Factor of 65% is then applied, resulting in a peak export value of 7.05c/kwh:

- 10.8c/kWh x 65% = 7.1c/kWh.

The 2.7% of avoided losses is then added as a separate transaction according to the wholesale energy rate.

Existing Tariff Method

Working through an example of the calculation shown in Figure 7, we will trace the peak VNM Credit export rate for trigeneration in the Ausgrid area using the Existing Tariff Method. This rate is 5.9 c/kWh, as shown in Table 5. The existing peak tariff for a large urban business is 11.3c/kWh. If the generator is connected at the HV system level, this means that 50% of the system costs are used, and the other 50% is credited, so value drops by half:

- 11.3c/kWh x 50% = 5.9 c/kWh[19]

A capacity support value of $338/MVA/day is also provided for this customer's tariff class. It is assumed that the trigeration operator runs the 4MW generator at full capacity during the key peak periods to meet the network conditions. 29% of this is used onsite, so 2.86MW of generation is exported. Therefore over the year the capacity credit is:

- 2.86MW x 0.95 power factor x $338/MVA/day x 365 days/yr = $335,000/yr

The 2.7% of avoided losses is then added as a separate transaction according to the wholesale energy rate.

Capacity Payment Method

[19] Values may not add due to a slight simplification for explanatory purposes.

Working through an example of the calculation shown in Figure 8, we will trace the VNM Credit for trigeneration in the Ausgrid area using the Capacity Payment Method. This rate is $474/MVA/day, as shown in Table 5. Firstly, take the total Ausgrid Long Run Average Cost of network as $363/kW/yr including capital plus operating costs.

If the generator is connected at the HV system level, this means that 50% of the system costs are used, and the other 50% is credited, so value drops by half:

- 363/kW/yr x 50% = $182/kW/yr

The value is then simply converted into $/MVA/day

- $182/kVA/yr x 0.95 power factor / 365 * 1000 = $474/MVA/day

It is assumed that the trigeration operator runs the 4MW generator at full capacity during the key peak periods to meet the network conditions. 29% of this is used onsite, so 2.86MW of generation is exported. Therefore over the year the capacity credit is:

- 2.86MW x 0.95 power factor x $474/MVA/day x 365 days/yr = $470,000/yr

The 2.7% of avoided losses is then added as a separate transaction according to the wholesale energy rate.

Locational Constraint Method

This method is applied and credit in the same way as the Capacity Payment method, but the example figure of $182/kW/yr would be substituted for the Long Run Marginal Cost of the preferred network solution in that specific constrained distribution zone. That is, if $10 million was to be spent on network upgrades to address 2MVA of growth, this would translate be calculated as:

- $10m/2MVA = $5m/MVA

Taking into account the approximate annuity value of 10% this can be annualises to

- $500,000/MVA/yr, or $500/kVA/yr.

The value is then simply converted into $/MVA/day

- $500/kVA/yr / 365 * 1000 = $1,370/MVA/day

4 OUTCOMES OF VNM CREDIT METHODOLOGIES

The calculated VNM Credits using each methodology are shown in Table 14, in c/kWh for the volumetric element, and in $/MVA/day for the capacity credits. The table shows calculated VNM Credits for DG connected at the low voltage system (the distribution network), and for connection as a High Voltage system. In the latter case the VNM Credit is a lower value, as less of the transmission and distribution network is credited. It should also be remembered that VNM Credit is **in addition** to any payment for the energy itself. The equivalent table using values from the Essential network is given in Appendix 2.

Table 5: VNM Credit values by each methodology (Ausgrid network), and typical network charges

METHODOLOGY	VNM CREDIT RATES/ EXPORT VALUES						TYPICAL NETWORK CHARGES
	Volumetric TOU (trigeneration) [1]	Volumetric TOU (solar PV) [1]	Existing Tariff	Capacity Payment	Locational Constraint		Large customer
DG CONNECTED AT LV SYSTEM							
PEAK Value c/kWh	10.7	3.3	9.2	-	-		11.3
SHOULDER c/kWh [2]	1.1	0.3	4.6	-	-		5.6
OFF PEAK c/kWh	0.1	0	2.4	-	-		2.9
Capacity Payment $/MVA/day	-	-	338 [3]	764	Zero or 1,370 [4]		338
DG CONNECTED AT HV SYSTEM							
PEAK Value c/kWh	7.1	2.2	5.9	-	-		11.3
SHOULDER c/kWh	0.5	0.1	2.9	-	-		5.6
OFF PEAK c/kWh	0.0	0.0	1.5	-	-		2.9
Capacity Payment $/MVA/day	-	-	338 [3]	475	Zero or 1,370 [4]		338

Notes:
[1] Volumetric TOU rates are technology specific, while the other methods are not. As for the purposes of this report the Volumetric TOU and Capacity Payment methods are calculated using publicly available data, it was not possible to take account of diversity in the timing of peak period at different network levels. This should be done in Stage 2 using data provided by the network partner.
[2] Shoulder values drop substantially below peak for Volumetric TOU method due to the much

lower assigned probability that the system peak would occur during the shoulder period (NB: based on UK data). If this is a true representation, it may suggest that existing tariffs are much less cost-reflective than Volumetric TOU.

[3] Capacity charges for the Existing Tariff method are set at the tariff the customer pays, so the base rate will always equal the network capacity charge

[4] The locational LUoS will be zero in areas that are not grid constrained, and the magnitude will depend on planned augmentation. Example high value shown in Table (1,370) is based on a constraint worth $500/kVA/yr.

The Locational Constraint methodology is entirely distribution area specific, and is intended to reflect the actual savings from avoided augmentation within the coming investment and planning period. A key distinction from other methods is that the Locational Constraint VNM credit would only be applicable where the network is both constrained and has augmentation investment planned. Note that this effectively takes a very 'reactive' short-term view to address load growth, as distribution projects are rarely planned for than 5 years in advance, and transmission projects 10 years in advance. The values entered for the Locational Constraint method in Table 14 are illustrative only, based on a cost of augmentation being equivalent to $500/kVA/yr constraint.

Typical network tariffs have been included for comparison with the calculated VNM Credit rates. As would be expected, the calculated values for VNM Credit are less than the typical network charges, although they are the same orders of magnitude.

The VNM Credit in the Volumetric TOU method is technology dependent, as the calculated value includes an adjustment for the generator availability (the F-Factor), so the table lists both modelled cases (Trigeneration and solar PV). Note that in this methodology, shoulder values drop substantially below peak due to the much lower assigned probability that the system peak would occur during the shoulder period.[20] If this is a true representation, it may suggest that existing network tariffs with similar peak and shoulder values are much less strictly cost-reflective than the Volumetric TOU method.

The capacity payments listed are the applicable daily payments, but the actual amount the DG operator receives depends on their minimum availability at the peak time, in whatever way that is defined. For example, this could be the minimum availability during the peak period on the peak day each year, month or quarter,[21] which is then paid for that period.

As noted in Section 2.1, the network value can either be a credit paid to the generator or customer, or a lower LUoS charge for the customer's locally purchased electricity. Thus the relationship between LUoS, NUoS and the VNM Credit is:

$$\text{LUoS} = \text{NUoS} - \text{VNM credit}$$

Figure 10 below shows the breakdown of the final VNM Credit and LUoS values as a proportion of NUoS, using the three different methodologies in Ausgrid's service territory

[20] although currently based on UK data.

[21] Capacity charges are made on this basis, except the customer pays according to their **maximum demand** in the nominated period (minimum generation is the inverse of maximum demand).

for both trigeneration and Solar PV. Note that overall, the largest VNM Credit is given by the Existing Tariff Method, a moderate value is given by the Volumetric TOU method, and the Capacity Payment method takes an 'all or nothing' approach and thus varies dramatically according to technology availability during peak periods. The substantial differences the size of the VNM Credit using three different, defensible methods indicate that DG value is somewhat subjective and critically depends on the underpinning assumptions and logic. We suggest that the primary reason for the differences in the Volumetric TOU and Existing Tariff values are the degree of cost-reflectivity intrinsic to each method. As the Existing Tariff method uses published network tariffs, which recover most revenue through volumetric rather than capacity charges, this results in much greater VNM Credit values for variable DG in particular.

Figure 10: VNM Credit values as a proportion of NUoS for Trigeneration and Solar PV (Ausgrid)

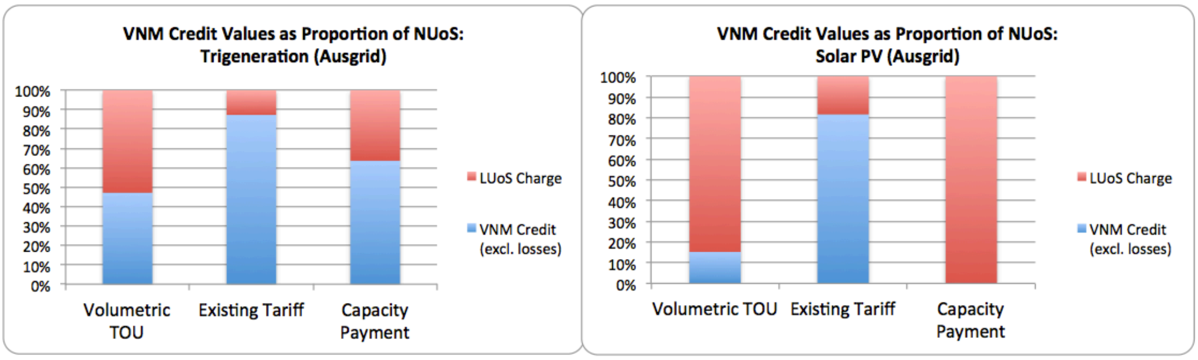


Figure 11 below compares the value of the VNM Credit by different calculation methodologies, using the two generator types modelled, namely a 4 MWe trigeneration system connected in the Ausgrid network area, and a 100 kW solar PV system connected in both network areas. Both generators are connected to the low voltage distribution system (so VNM Credits calculated are at the higher end of potential LUoS values according to their connection location). The value is normalised to a volumetric credit for the exported electricity, to enable an easier comparison. Figure 20 in Appendix 2 gives the actual calculated values for the two situations.

The locational credit is site-specific using hypothetical values, and thus cannot be compared directly with other methods, so will not be included in this discussion.

All three methods (Volumetric TOU, Existing Tariff, and Capacity Credit) deliver credits to trigeneration of between 5 and 10 c/kWh, as this is a dispatchable source that the operator can choose to operate at the local distributor's peak times (the model assumes operation throughout the key local peak periods to reap the capacity credit component). The Existing Tariff method gives the highest value, because all generation occurs during peak and shoulder periods so this generator is able to make full use of both volumetric and capacity rates. The Volumetric TOU method yields the lowest value, as capacity risk is dealt with in a probabilistic fashion, using an F-Factor for trigeneration of 65%, even though the particular DG may have been producing at higher reliability throughout the year. This method provides no incentive to increase generator availability.

The Volumetric TOU method gives a very low credit to PV, of under 1 c/kWh. This is because a fixed "F-Factor" is applied to PV, which reduces the calculated VNM Credit for the network level by 80% in the Ausgrid area, and by 97% in the Essential area (see Table 2, Section 3.2.1 for a list of F-Factors).

The Existing Tariff method results in credits of 5 c/kWh and 9 c/kWh for solar PV connected to the LV system (for Ausgrid and Essential respectively). Under this method, the reward for solar is higher in Essential Energy's network, partly because the network tariffs are higher, but primarily because Essential's shoulder rates (when most PV exports occur) are in fact identical to the peak period rates.

The capacity credit method (and locational constraint method) assign no value to solar PV in either network service territory, as the peak period operational criteria is strictly defined to credit the minimum operational capacity during the peak period, which in both networks run until 8pm (as there is at least one half hour period after sundown). This would reward PV if coupled with battery storage for example, but not without. However, this could be argued as undervaluing solar particularly in the case of Ausgrid, as solar PV generation has a generally strong correspondence with system peak for much of the Ausgrid 2-8pm peak period, yet receives no value under this method. For Essential Energy, zero may be closer to the true capacity value from PV without storage given the timing of the peak periods from 7-9am and 6-8pm does not correlate well with solar production.[22]

Figure 12 shows what happens to network payments under for the two modelled technology cases, both connected to the low voltage distribution network. There are a number of points to note:

- In the situation where there is DG, but there is not a VNM credit:
  - The network operator effectively gets a windfall gain to the value of the VNM Credit, as there is a benefit to the network, but revenues are not affected.
  - The retailer effectively get a windfall gain to the value of the avoided losses, as the customer is charged full losses, but lesser losses are incurred and the retailer needs to purchase less centralised energy to balance supply and demand.
- In the case with DG and the VNM Credit, the VNM Credit is given to either the generator, or the participant customer (in reality it could be shared). The network operator is neither disadvantaged nor advantaged, providing the credit is correctly calculated, as revenue is reduced by the same amount that costs are reduced.

However, it is difficult to analyse the stakeholder and societal effects without also considering energy costs, which are a major driver for considering DG in the first place. This is not in scope for this work, but should be considered for inclusion in Stage 2 of the project.

[22] Note, however, that Essential's peak and shoulder network tariffs are identical, suggesting a roughly equal probability of the system peak occurring during peak or shoulder periods. Therefore the strong bias that the Volumetric TOU and Capacity Payment methods place on DG capacity solely during the peak period, may not be a true reflection of the system value of DG.

Figure 11: VNM Credit value comparison by methodology and generator types

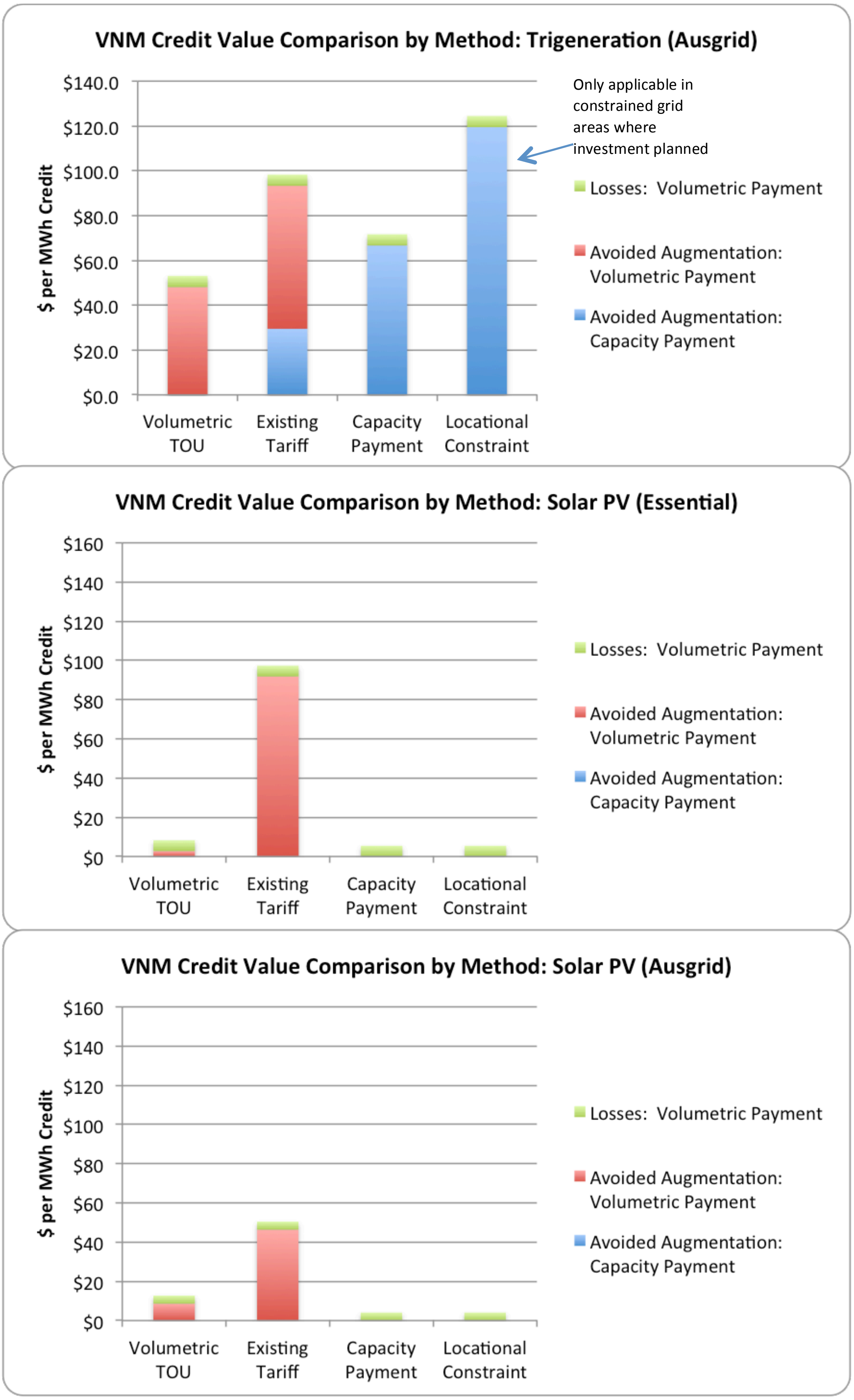
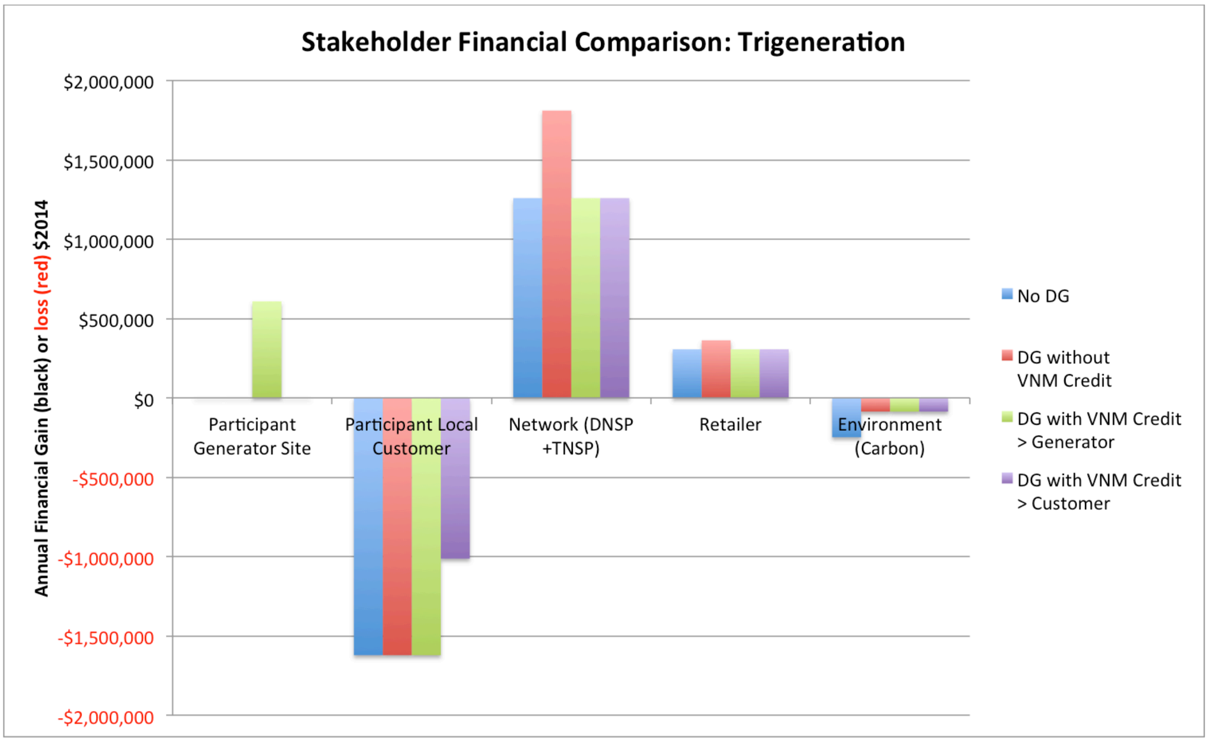
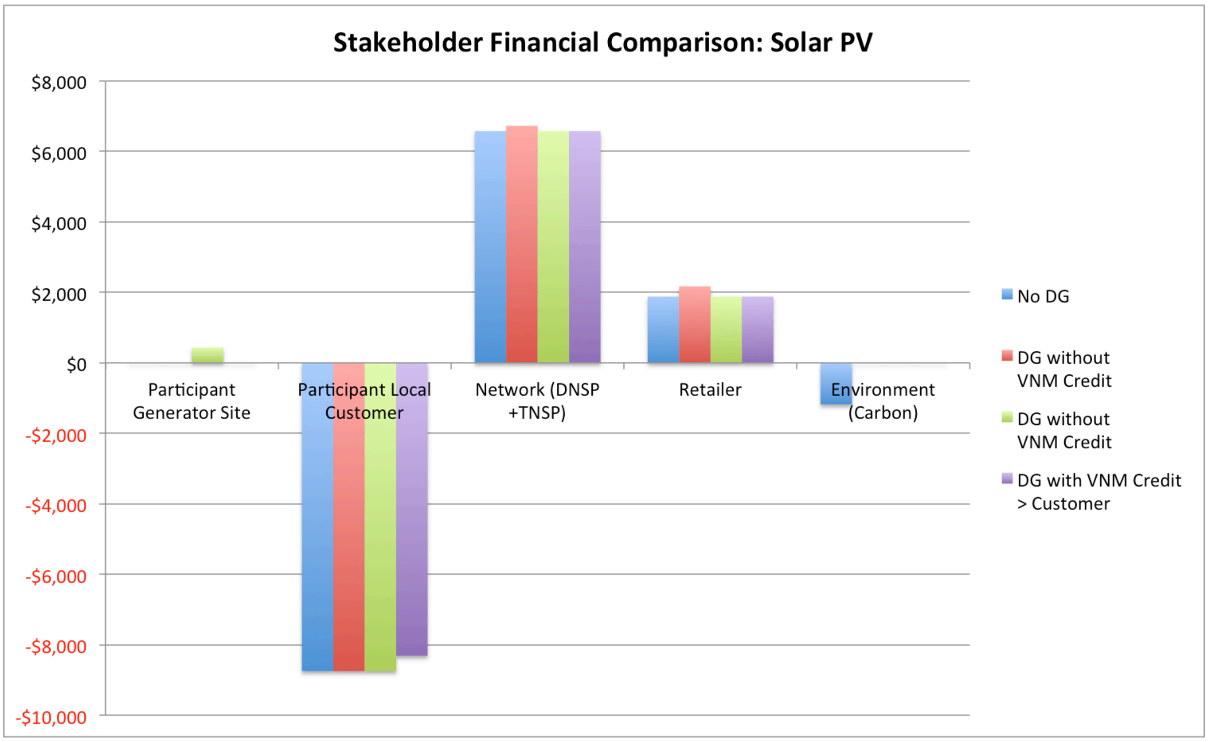


Figure 12: Network charges by stakeholder, comparison for trigeneration and solar PV at the LV system, using the Volumetric TOU calculation method for VNM Credit





5 MARKET PATHWAY ANALYSIS

This section of the report has been undertaken with funding from the City of Sydney, in parallel with the TEC project outcomes.

5.1 OVERVIEW

The two different overarching systems identified in Section 2 are Virtual Net Metering (VNM), where the DG has a relationship with a customer, and Distributed Energy Credit (DEC), where the payment is made with no requirement (or facilitation) of the DG selling to a group of customers or to themselves.

In a DEC system the transaction pathways are straightforward in that a DEC credit is paid to the DG by the retailer, and energy transactions are not affected as the customer is not linked to the DG. This is not to imply that the introduction of such a system is straightforward, as it would require both a regulatory change to require a Distributed Energy Payment, and calculation of the credit itself.

Transactions in VNM are more complex, as generation exported from the DG requires "netting off" with the customer purchasing the distributed energy. This section examines how network charges could operate for local generation, and then maps the transactions required for valuing DG via the DG participant pathways described in Langham, Cooper and Ison (2013). The section then gives an overview of how the metering and billing logistics could work, and finally any obvious regulatory issues relating to the VNM transactions. **All situations assume that DG is not the sole energy supplier to the purchasing customer**. Therefore the purchasing customer still holds a regular contract with a retailer for the balance of their energy needs.

The participant pathways identified are:

Type 1 Single entity VNM (self generation). Where electricity generated at one site is to be used at another location of meter(s) owned by the same entity (i.e. a council has space for solar PV at one site, but demand at a nearby facility)

Type 2 Third party VNM – DG sells to local customer. This has some variants:

i. Sale to single third party customer within a local distribution area
ii. Sales to local group of customers within a local distribution area
iii. Sales to single or group of customers, but not restricted to local area[23]

Type 3 Community or group owned DG sells to shareholders

i. within local distribution area
ii. with no geographical restriction[23]

---

[23] This report will restrict discussion to those situations where the energy is used within a local distribution area. In cases where there is no geographical restriction, the VNM and energy sales requirement s would be similar, but the application of the Local Use of System charges would not be relevant.

Type 4 Retail Aggregation. Retailer/ aggregator (which could be a community retailer established for the purpose) aggregates exported electricity generation from multiple DGs and resell to local customers.

5.2 LUoS CHARGES AND VNM CREDITS – TRANSACTION PATHWAYS

Figure 13 shows four different ways that the network charges could be applied to the locally generated and consumed electricity. Note that this is only the network charge, and not the energy charges. In all cases the VNM credit is the calculated network costs saved by local generation.

In example a) the benefit of the avoided network costs accrues to the generator. The customer pays the normal network tariffs on all the electricity they consume, and the retailer pays the VNM credit to the generator. The network operator receives the lower network charge for the locally generated electricity, reflecting the lower costs incurred.

In example b) the benefit of the avoided network costs accrues to the customer purchasing the DG. The customer pays the normal network tariffs on all the electricity they consume, but the retailer applies the credit to the customer's bill. The network operator receives the lower network charge for the locally generated electricity, reflecting the lower costs incurred. The DG receives no network credit, but the benefit is seen by the generator as a higher negotiated energy price with purchasing customer

In example c), the benefit accrues to the customer, who pays a lower charge on the locally purchased electricity. This is in fact the same net transaction as b) above, but is conceptualised as a single transaction.

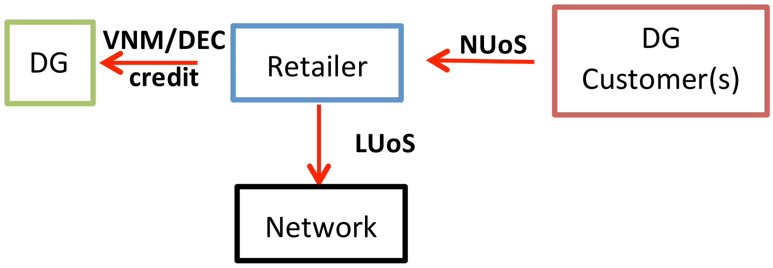
Example d) covers the situation where the generator pays a charge to the network for the use of the local network, either to supply themselves, or to sell energy direct to a customer. If selling direct to another customer, the other customer would need to be exempt from paying network charges on the locally generated component. This could be done through an approved meter data reconciliation process, so the purchasing customer's retailer never "sees" the locally generated energy).

These alternative pathways are also shown in Figure 14 to Figure 17 in combination with energy transactions.

Figure 13: Network transaction pathways – Types 1-4 VNM

<table>
<tr><th>NETWORK CREDIT/CHARGES FOR LOCAL GENERATION</th><th>Notes</th></tr>
<tr><td>

a) CREDIT TO GENERATOR



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- Customer purchasing DG pays full NUoS
- DG receives VNM/DEC credit for exports
- Network recieves LUoS
- Note that in type 1, the DG and the customer are the same entity
- This is the only viable pathway for Distributed Energy Credit

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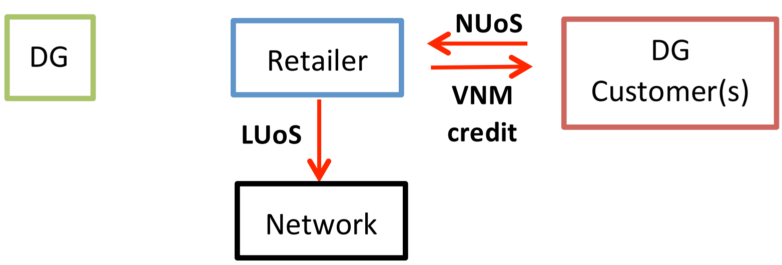
b) CREDIT TO CUSTOMER



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- Customer purchasing DG pays full NUoS but receives VNM credit (which nets out at paying LUoS as in c) below but occurs as two transactions)
- DG receives no network credit, assume this benefit is passed on in negotiated energy price with purchasing customer
- Network recieves LUoS

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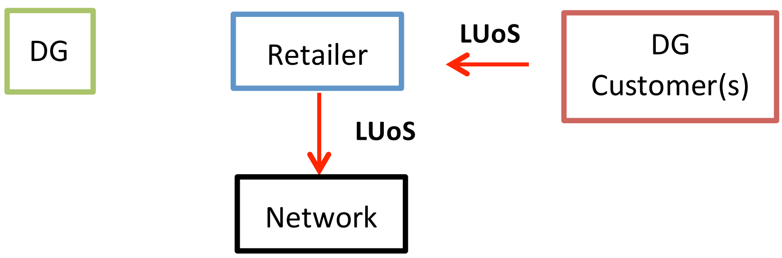
c) REDUCED CHARGE TO CUSTOMER



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- Customer purchasing DG pays LUoS (rather than NUoS) in one transaction. The net transaction is the same as b).
- DG receives no network credit, assume this benefit is passed on in negotiated energy price with purchasing customer
- Network recieves LUoS

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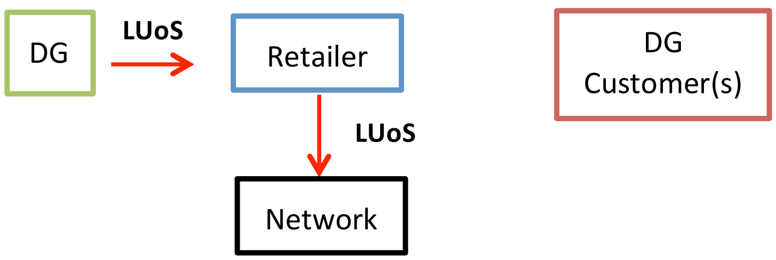
d) DG PAYS DIRECT FOR USE OF NETWORK



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- DG pays LUoS charge for network use either via retailer OR directly to network
- Latter would require financial relationship (between DG and network) that does not yet exist
- Purhasing customer is exempt from network charge on DG energy

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</table>

A preliminary comparison of the implications, pros and cons of the different network transaction pathways is shown in Table 6 below. Confirmation of several transactional issues and preferences from stakeholders are required during Stage 2 of the project before a preferred arrangement can be established.

Table 6: Preliminary Comparison of Network Transaction Pathways

Scenario			Required for Network Value Calculation				Retailing		Price Certainty				
Network transaction pathway	**Framework**	**Network value to be calculated**	**Generator Tariff**	**Generator Metering**	**Customer Tariff**	**Customer Metering**	**Retailer involvement**	**Issue if retailer bypassed**	**For Generator**	**For Customer**	**Pros**	**Cons**	**Preference**
a) Credit to generator	DEC	VNM Credit	If using Existing Tariff Method	Yes	No	No	Preferred	Network needs transaction path to pay DG	Yes	Indirect	Not dependent on customer tariff	Broader reach so may be harder to pass; may require cap on local generation to implement	Higher
	VNM	VNM Credit	If using Existing Tariff Method	Yes	No	Yes	Preferred	Network needs transaction path to pay DG	Yes	Indirect	Not dependent on customer tariff	Potentially less price certainty for consumer	Higher
b) Credit to customer	VNM	VNM Credit	If using Existing Tariff Method based on generator tariff	Yes	If using Existing Tariff Method based on customer tariff	Yes	Preferred	Network needs transaction path to pay customer	Indirect	Yes	POSSIBLY not dependent on customer tariff	Potentially less price certainty for generator	Higher
c) Reduced charge to customer	VNM	LUoS (via VNM Credit)	Yes	Yes	Likely	Yes	Preferred	DG's billing potentially more complicated as have to deal with different existing customer tariff classes	Indirect	Yes	*More* reflective communication of true network transaction	Unless a fixed LUoS matching the VNM Credit calculation is made, will be dependent upon varied purchasing customer tariffs	Lower
d) DG pays direct for use of network	VNM	LUoS (via VNM Credit)	Yes	Yes	No, but customer needs to be exempt from network charges on locally purchased energy through reconciliation process	Yes	Optional	DG needs transaction path to pay network	Indirect	Indirect	*Most* reflective communication of true transaction; may be more amenable to retailer bypass	LUoS is less intuitive if core calculation is for VNM credit	Higher

5.3 TRANSACTION PATHWAYS FOR VNM

This section examines the transaction pathways required for VNM. In most cases there are variations, such as whether the customer pays LUoS on locally generated electricity, or the DG receives a VNM credit. The transactions involved have been simplified at this stage, and in particular do not deal with electricity that is exported but does not match demand at the remote site. This should be considered during Stage 2.

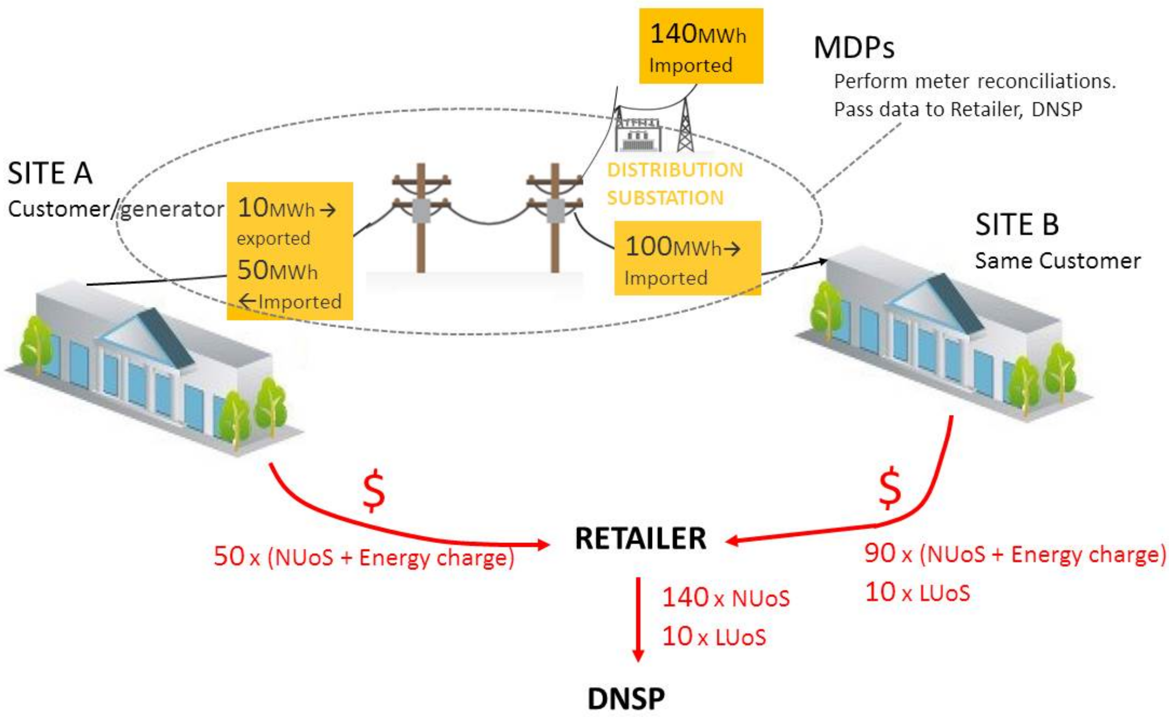
5.3.1 Type 1 Single entity VNM (self-generation)

The energy and money flows for single entity VNM is shown in Figure 14, in which a customer uses electricity exported from one site at another one of their own sites. In the example shown, the customer generates at Site A. In addition to electricity they generate and use on site, they import 50 MWh, and export 10 MWh. The 10 MWh exported is used at Site B, which uses 100 MWh in total. 140 MWh has to be imported from outside the distribution network to supply Site A and Site B.

The flows of electricity are measured by the Meter Data Provider (MDP), who nets off the exports and imports, and supplies the reconciled data to the retailer (see Section 5.3.3 for further discussion of the logistics required).

The associated transactions are shown in red: the DNSP receives NUoS on the electricity imported from outside the distribution area, and LUoS on the locally generated electricity. The customer pays their normal charges for all the electricity imported from outside the area, no energy charge for the electricity they generate themselves, and LUoS (rather than NUoS) for the electricity they generate at one site and use at another.

Figure 14: Transaction pathways for Type 1 Single Entity VNM (self-generation)



5.3.2 Type 2 Third Party VNM (DG sells to customer/s) and Type 3 VNM (Community Renewable Energy)

Figure 15 and **Figure 16** show the transaction pathways when the DG's exported energy is sold to a third party. The energy and money flows are very similar in Type 2 and Type 3, although the regulatory impediments may differ (see Section 5.5.2).

In this case Entity A generates and exports, and the energy is used by either their customer, or in the case of the community owned DG, by their shareholders. While only one "Entity B" is shown in Figure 15, there could be multiple customers on exactly the same basis.

In both examples shown the energy charge goes directly to the DG. This energy payment could be brokered via a retailer, although there may be complications regarding who sets the price.

The VNM credit is shown as paid to the DG in Figure 15, so the customer pays the retailer the full NUoS for all the electricity they consume. It is presumed this is reflected in a lower energy price charged to the customers by the DG, and has the advantage that the revenue flowing to the DG is more predictable.

The network charge transaction could also be structured as shown in Figure 16, so that the customer pays LUoS and the DG presumably charges a higher energy price. Figure 16 shows the case where the DG is a community owned facility, which is supplying energy to shareholders within the local network area. Shareholders pay the energy charge for the locally generated portion of their energy direct to the DG, and only pay LUoS (instead of NUoS) on that portion.

Note that in both Type 2 and Type 3 VNM, the VNM credit can be paid to the generator or to the customer, or the customer can pay LUoS instead of NUoS on the energy purchased from the DG.

Figure 15: Transaction pathways for Type 2 – Third Party VNM (with VNM credit to generator)

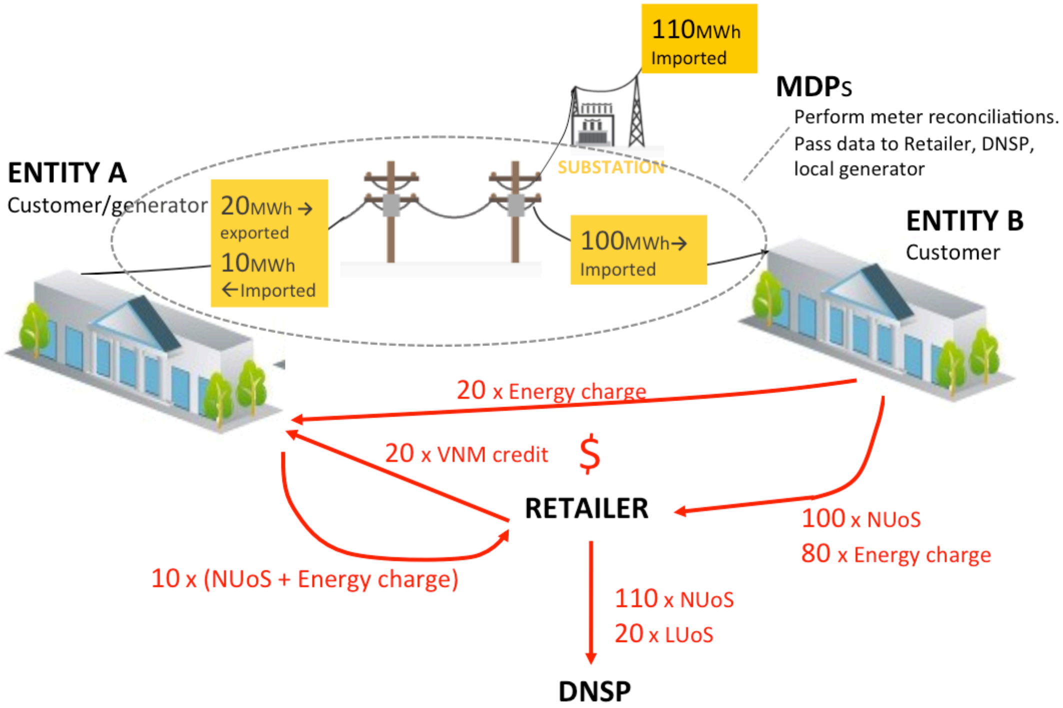
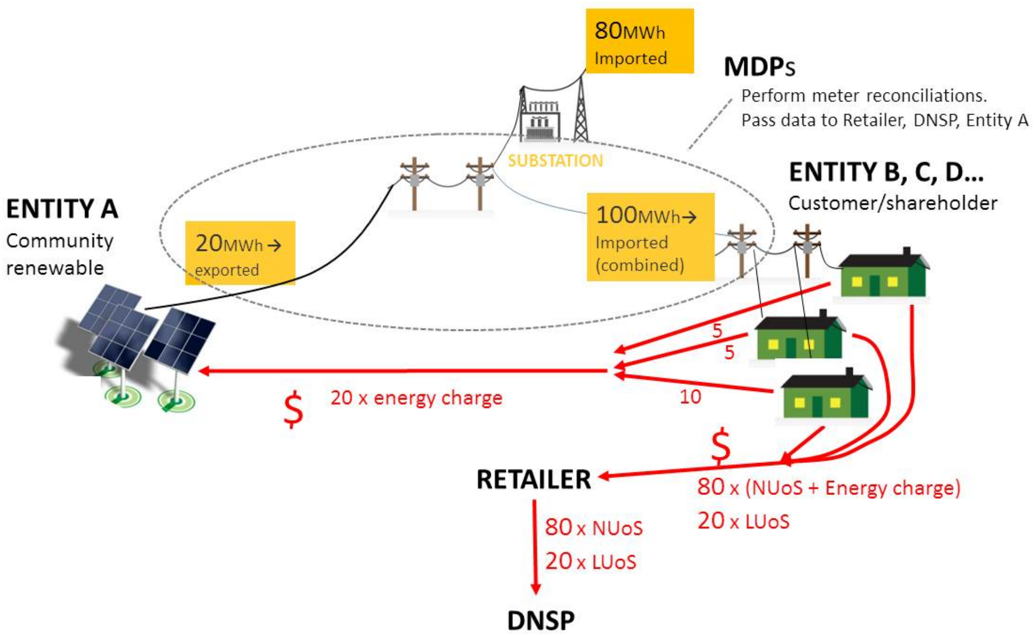


Figure 16: Transaction pathways for Type 3 VNM – Community renewable energy (with reduced network charge to customer)

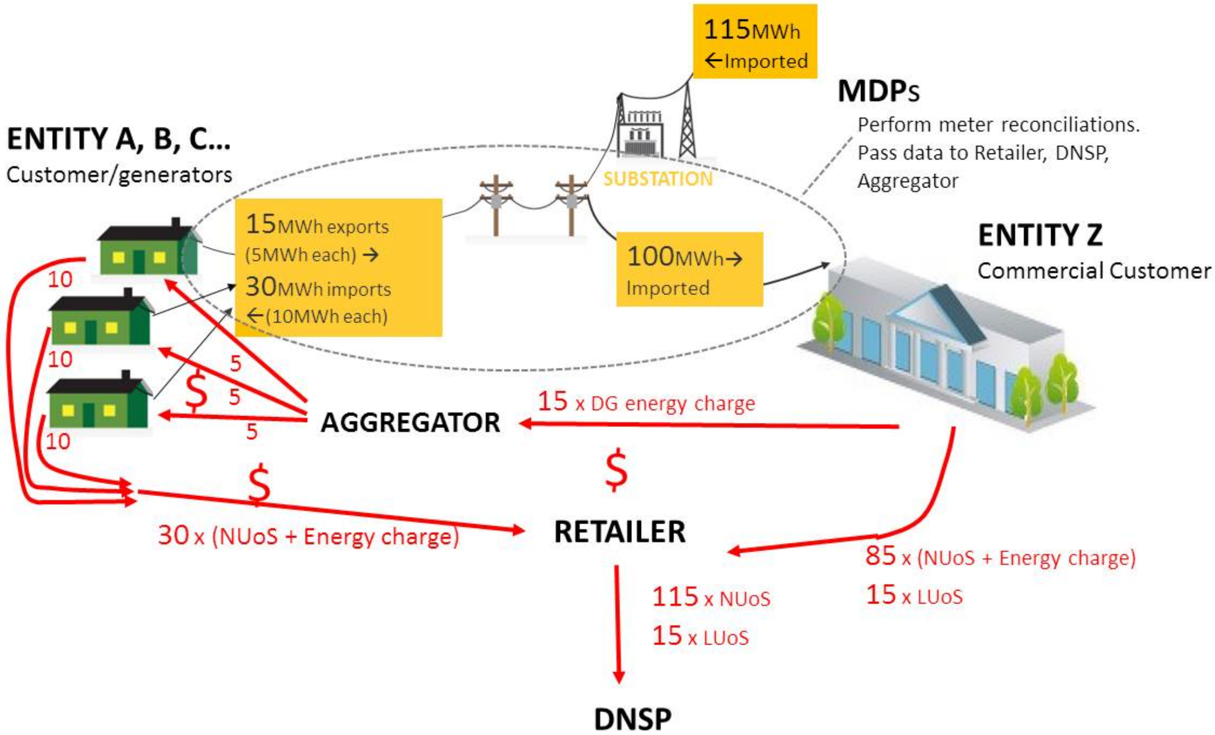


5.3.3 Type 4 Aggregator acts for multiple small DGs

Figure 17 shows the example of an aggregator who acts to pool exported electricity from multiple small players, such as rooftop solar. Entity Z purchases exports, and pays directly to the aggregator, who passes on the payments to the small DGs. The transaction is shown with Entity Z paying LUoS rather than NUoS on the locally generated electricity, although this could be structured so that the retailer pays the aggregator (or the customer/ generators) a VNM credit.

The Aggregator would require either a retail authorisation or an individual exemption from a retail licence. It is possible that if they obtain an authorisation, they may be the retailer (so it is retailer/ aggregator), or that an existing retailer decides to offer this service. In the case of an aggregator set up to be an intermediary to sell small renewable exports they may not wish to take on all the retail roles, such as balancing supply, purchasing from the spot market or other suppliers, paying pass through charges to the DNSPs and AEMO.

Figure 17: Transaction pathways for Type 4 VNM – Retail aggregator

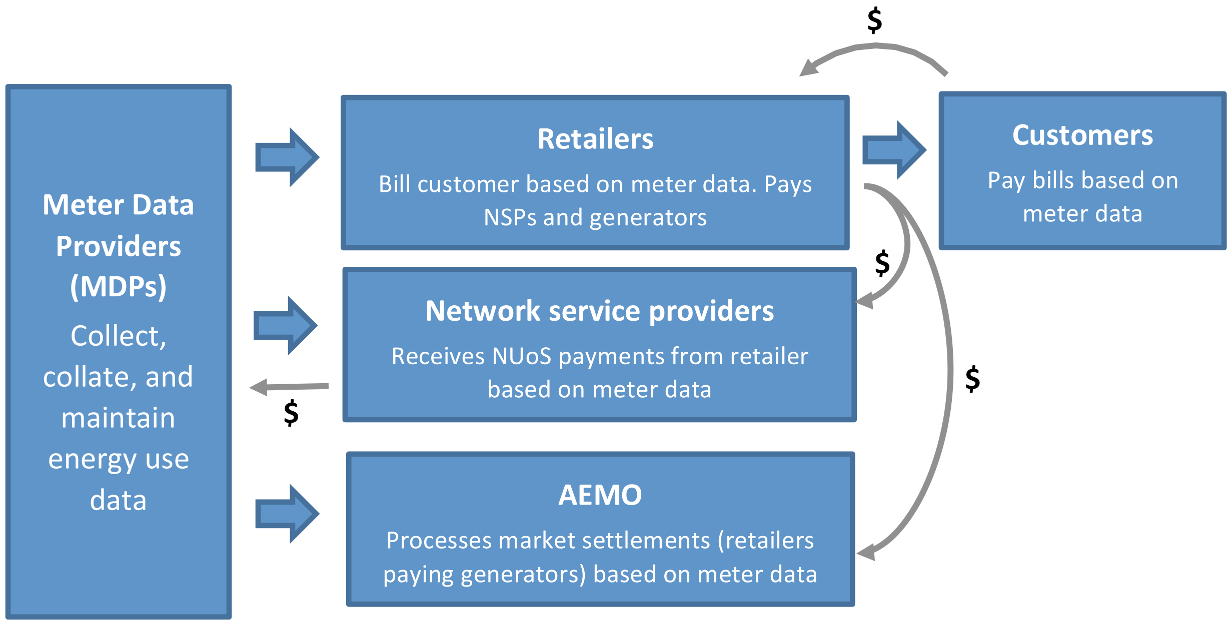


5.4 LOGISTICS: METERING AND BILLING

In order for the VNM transactions to occur, the exported generation must be netted off at the import site or sites at half hourly intervals using interval meters, and the reconciled data used to calculate charges, so that the customer is charged appropriately for energy used, and the correct network charges or VNM credits are applied.

The current logistics associated metering and billing payments are summarised in Figure 18 below. The thick blue arrows represent the flow of metering data; the thin grey arrows indicate financial flows.

Figure 18: Metering data flows and financial payments in the NEM – current situation



According the NEM Rules Schedule 7.1, Metering data providers (MDPs) are responsible for:

- the collection of metering data (by manual or remote telecommunication means)
- the processing and delivery of metering data
- maintaining the metering data services database
- maintaining electronic data transfer facilities for data delivery

Retailers, NSPs, and the Australian Energy Market Operator (AEMO) access metering data via electronic data transfer from the metering data services database. Retailers collect payments from the customer and pay the NSPs directly for NUoS charges. The retailers pay the generators for the energy supply either directly via a PPA or through the market via AEMO settlements process.[24] MDPs are paid for their services by the DNSPs.

In 2014, there were 20 registered MDPs in the NEM. For residential and small business customers, the DNSPs typically fulfil the function of MDP. For larger commercial businesses, third party metering businesses often fulfil the role as MDP.[25]

VNM would require the meters of the generator(s) and customers(s) to be matched and the interval meter data 'reconciled' or 'netted-off'. This process could be performed by the MDPs, retailers, or DNSPs. The MDPs are arguably best positioned to carry out the reconciliation, with the reconciled data provided to retailers and the NSPs as per usual. The MDP may also need to provide data directly to the DG in situations where the DG bills the customer directly for energy.

[24] Need to confirm with AEMO in Stage 2 that PPAs bypass the settlements process.
[25] For a complete list of MDPs in the NEM, go to http://www.aemo.com.au/Electricity/Retail-and-Metering/Metering-Services/Accredited-Metering-Data-Providers-National-Electricity-Market

Figure 19 shows proposed data and financial flows if VNM is introduced (the financial flows in and out of the DG operator are dotted as there may or may not be a retailer involved in the transaction). It is assumed the MDP would supply reconciled data to the retailers, the NSPs, and potentially the DG in the case where the DG bills customers directly for exported energy. However, the operational capabilities and transaction costs involved to achieve the reconciliation requires exploration with both MDPs and retailers (recommended for exploration in Stage 2 of the project).

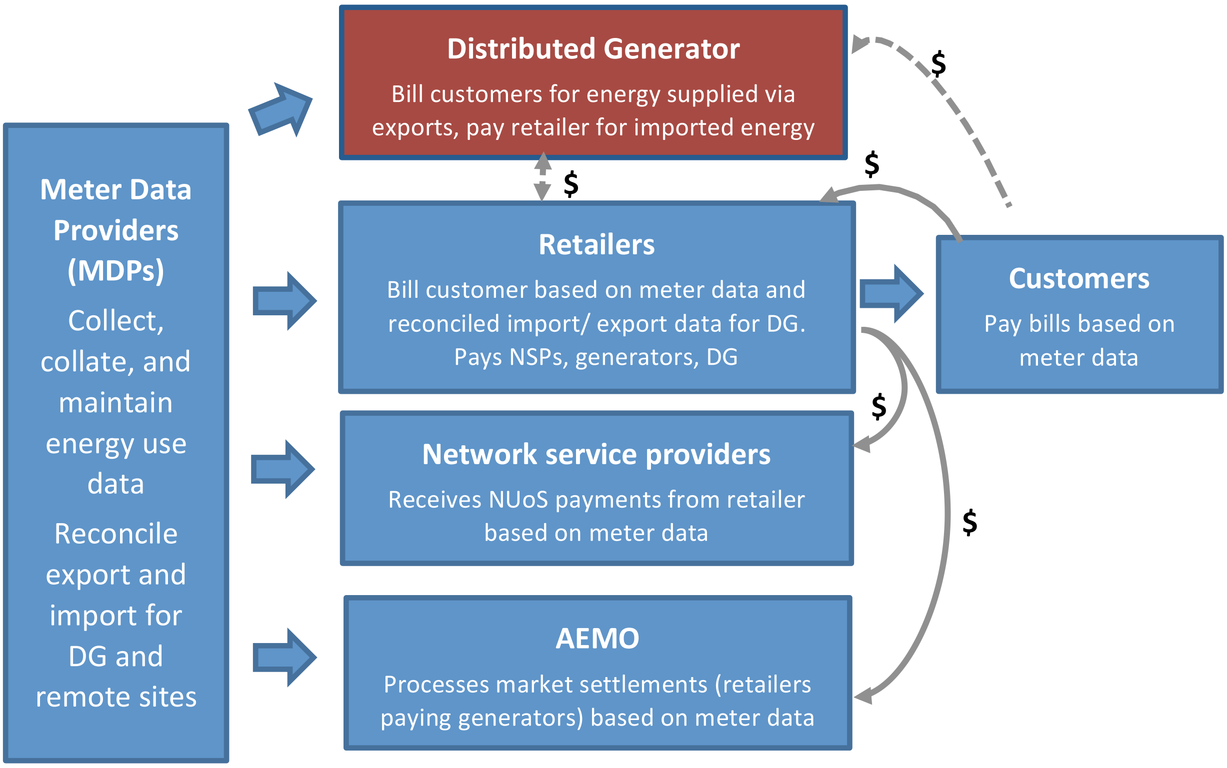
The retailers would apply LUoS or NUoS charges and VNM credits to the local generation units, adjusting pass through payments to the NSP and potentially paying the distributed generator the VNM Credit.

In all circumstances it is assumed that the DG purchasing customer also holds a contract with a regular retailer for their 'top up' energy – that is, the remaining energy consumed after their local DG energy purchases have been netted off. For the different VNM arrangements shown in **Figure 14** to **Figure 17** where a retailer brokers the transaction between the DG and the purchaser, the customer would receive two separate bills, unless the DG and customer retailers were the same entity. In the case where there was a direct relationship between the customer and the generator (where the generator receives a retail licence exemption), the customer would receive two bills. These three scenarios are shown in **Table 7** below.

Table 7: Number of bills involved in VNM transaction plus top-up energy

Scenario	DG's Retailer	Customer's Retailer	Number of bills
1	Retailer A	Retailer B	2
2	Retailer A	Retailer A	1
3	None (Exemption)	Retailer A	2

Figure 19: Metering data flows and financial payments with VNM



5.5 METERING AND RETAIL REGULATORY BARRIERS TO VNM

There are two aspects to VNM that need to be considered with regard to regulatory barriers (in addition to any regulatory barriers on the network side regarding DEC/VNM credits). These are the requirement for reconciliation of metering data, and the requirement for an entity selling electricity to hold a retail authorisation.

5.5.1 Requirement for reconciliation of metering data

VNM requires the reconciliation of metering data from two or multiple premises, and supply of the reconciled data to the retailer, the DNSP, and potentially the DG operator. There appear to be no rules that preclude the supply of data, but it is not a required service. During Stage 2 an opinion should be sought from the AER as to whether it would require a rule change if VNM meter reconciliation were to become standard practice, or a required service to be offered by MDPs and retailers. The operational requirements and potentially transaction costs may require identification prior to any rule change being proposed.

5.5.2 Requirement to hold a retail license

Many of the VNM transaction pathways described earlier would be brokered by a retailer, and as the Retailer's authorisation would be used to on sell the DG energy to customers. There are some circumstances described where a direct relationship would exist between the customer and the DG. In this circumstance, under the National Energy Retail Law, anyone who sells energy for use at premises must have either a retail authorisation, or an exemption from the requirement to hold an authorisation. Exemptions may either be individual, in which case the seller must make a specific application to the AER, registrable, in which case the seller must register with the AER (but no explicit AER approval is required), or deemed, in which case the seller does not need to inform or register with the AER. The AER published a revised guideline in 2013 to exemptions, including a list of deemed and registrable exemptions (AER, 2013b). The requirement for a retail authorisation is discussed below for Types 1 – 4 VNM, as tentatively confirmed by the AER in April 2014.

Type 1 – Single Entity VNM

A distributed generator supplying energy to themselves at a remote site would not require a retail authorisation, because:

a) This arrangement may not constitute selling and therefore may not require an exemption; or
b) This arrangement would in any case be exempt under class D8 *Persons selling energy to a related company.*

Type 2 – Third party VNM

When a distributed generator sells to other customers, deemed exemptions apply in some cases:

a) if the DG is a local, state or federal government, selling to *non-residential* customers they would be eligible for a deemed exemption under Class D10 *Government agencies, other than housing authorities, selling metered energy to non-residential customers*. This would apply whether the customers are in the local distribution area or not, and whether it is one customer or many provided they are non-residential.

The above is a very restrictive class exemption. If the DG is not a government agency, or wishes to supply residential customers, it appears that a retail authorisation or an individual exemption (which may be granted if the market is niche or DG size is small) or would be required, unless the membership model of VNM (below) is found to classify for an exemption, and could apply.

Type 3 – Community group selling to their shareholders

In this case the DG is owned by a community group, and potentially supplies the owners or members of the group. Two variations are given:

a) The DG is owned by a Special Purpose Vehicle, which is owned by shareholders. Energy is only sold to shareholders by the distributed generator.
b) The DG is owned by a Special Purpose Vehicle, which runs a membership organisation to receive the energy. Anyone may join the membership organisation. Energy is only sold to members.

It is possible that the relationship is covered by “selling to a related company” class exemption, or may not be considered selling, similar to the Type 1 self-generation case.

Type 4 – Retail aggregator

It is assumed that in this case either a retail authorisation or an individual exemption would be required by the DG.

During Stage 2 of the project a formal opinion should be sought from the AER on whether the above Type 1-4 models would eligible for exemptions as described, particularly as relates to Type 3, which was an situation with which the AER was unfamiliar.

5.6 NETWORK REGULATORY BARRIERS TO VNM AND DEC

There appear to be no rules that specifically prevent the networks from utilisation of a VNM/DEC Credit or LUoS charge; however, neither is there a requirement to offer this tariff class. Thus it is possible to pursue on both of the following avenues:

1. Work with network partner/s to establish a VNM Credit precedent.
2. Propose a Rule Change to mandate that all networks offer a VNM tariff class.

1. Work with network partner/s to establish a precedent for offering a VNM Credit

Under the current rules, the DNSP service classification categories[26] are highly prescriptive and must be submitted by the DNSP in their determination application to the AER, and subsequently approved by the AER. Service classifications are set during the preparation for a regulatory determination, some 23 months in advance. The NSW DNSP applications for the 2014-2019 determination period are due in May 2014 and Queensland due in October 2014. Therefore it is unlikely that a new service classification will be available in these states via the current AER determination process. Otherwise, any new charge such as a LUoS charge (even if classified as a type of DUoS charge) would need to wait until the next determination period to get approval (AER, 2014).[27]

The other inherent issue with this approach is that DNSPs currently have little incentive to propose such a tariff class, and the establishment of a precedent by one or two networks is unlikely to spur a rapid replication of the approach. As a VNM credit arrangement is a financial transfer from networks to a third party, it can initially appear to be a short-term revenue loss, despite medium-term or long-term augmentation avoidance. Yet as these generation export projects would not happen in the absence of a VNM Credit mechanism, proponents are left to focus on behind the meter arrangements where networks lose greater revenue. As such, a VNM credit approach in fact creates a new LUoS revenue stream for DG exports where there was previously none. It is anticipated that this could form a valuable part of the network business model into the future. Communicating this message is challenging given the inherent complexity of the VNM concept, and therefore combining this ‘network partner’ approach with a broader Rule Change proposal (#2 below) may be necessary.

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[26] Service classification categories include the different types of DUoS, TUoS and NUoS charges.
[27] This should be confirmed with the AER during Stage 2 as it has important implications with regard to actions flowing on from Stage 2 of this project.

2. Propose a Rule Change

This approach would seek a Rule Change requiring networks to offer a LUoS/VNM Credit tariff class, calculated according to a consistent prescribed methodology. The application of this methodology buy each network business would require approval by the AER as part of the regular tariff approval process. The primary concern with this approach is that applying for a Rule Change is a lengthy processes requiring broad support from market participants. This present a issue not only in terms not time to make VNM operational, but also a barrier in that the initial beneficiaries of VNM – distributed generators and customers – are small and fragmented in their advocacy.

6 DISCUSSION AND RECOMMENDATIONS

6.1 METHODOLOGIES COMPARED

As discussed in Section 2, there are two distinct questions on how to value DG: firstly whether this is via a Distributed Energy Credit which is applicable to all DG regardless of customer linking, or via a VNM system where the DG is linked to the purchaser of the energy. There are four methodologies presented here for calculating the VNM Credit. This section looks briefly at the pros and cons of VNM versus DEC, and then considers the suitability of the four calculation methodologies for each, and whether any of the methods preclude benefit sharing with customers.

Table 8 compares VNM and DEC. The key points are that VNM is more obviously cost reflective, as the DG is getting a benefit directly linked to the customer using the electricity. However, this requires a relatively new practice of netting off exports against customer usage, which has a transactional cost (as yet unquantified) that may be hard to justify for small-scale exports. Where reconciliation of multiple customer *energy* transactions are desired (e.g. precinct trigeneration or some community energy projects), this metering would be required even if using a DEC framework.

Table 8: Pros and cons of Virtual Net Metering compared to Distributed Energy Credit

	Advantages	Disadvantages
Virtual Net Metering	**Key points:** **More obviously cost reflective** **Allows benefit sharing**	**Key points:** **More complexity to administer**
	Ensures that DG is being used in predicted network level, as DG linked to TOU uptake at customer premises[28]	Requires metering of customer and DG to be linked, with corresponding software and operational cost (may have to occur anyway for community or precinct trigeneration).
Universal Distributed Energy Credit	**Key points:** **Reduces administrative burden in network transaction (see notes)** **Universally available and predictable**	**Key points:** **Less cost reflective** **Less incentive to match generation to load** **Does not allow benefit sharing with customer** **May be hard to gain acceptance within current market arrangements**

[28] This only applies if customers are required to be in local Distribution Area.

	No netting off of DG and customer metering required for network transaction, however, for where reconciliation of multiple customer *energy* transactions is desired this metering would be required even if using a DEC framework. Predictable for DG, as rates can be set and published.	Independent of customer load, so DG not incentivised to match generation and load. May require additional technical measures to limit or re-value DG requiring upstream export between distribution levels.

Table 9: Suitability of credit calculation methodologies with VNM and DEC systems

	Volumetric TOU	Existing Tariff	Capacity Payment	Locational Constraint
Calculation independent of DG customer	✓	X	✓	✓
VALUATION SYSTEM				
VNM Type 1 Single entity	✓	✓	✓	✓
VNM Type 2 Third party	✓	Yes Multiple customers could cause problems	✓	N/A
VNM Type 3 Community owned	✓	✓ (same as Type 2)	✓	N/A
VNM Type 4 Aggregator	✓	Maybe – unclear how to select tariff	✓	✓
DEC	✓	Maybe – unclear how to select tariff	✓	X
TARIFF CAN BE PAID TO:				
Generator	✓	✓	✓	✓
Customer	✓ (if VNM)	✓	X	X

Table 9 compares the suitability of the four methodologies with VNM and with DEC, and whether the credit may be given to either the generator or the customer. A VNM system is required if network benefits are to be allocated or shared directly with customers, as in a DEC system there is no link between customer and the DG, and no mechanism to allocate benefits to individual customers. Of course, all customers benefit if the overall system costs are lowered.

The Volumetric TOU is compatible with either system, and may be credited to either the purchaser or the generator, although it fits most easily as a credit to the generator.

The Existing Tariff method is most intuitively cost reflective, as the credit values assigned are based on what customers currently charged for network services. Indeed, provided the percentage allocation of costs to each network level is accurate, the Existing Tariff method exactly mirrors the cost reflectiveness of current network charges. The Existing Tariff method is most suitable for a VNM system, as a customer specific network tariff is one of the key data inputs to the calculations. It is entirely possible to allocate benefits to DG, customer, or on a shared basis. Multiple customers on multiple network tariffs would make the calculation of the VNM Credit rather complicated, and may result in the need for retrospective adjustment to the credit value. It is possible to use the Existing Tariff method in the absence of a customer link, but it means allocating a network tariff, perhaps deemed according to the customer characteristics in the DG area.

The two capacity payments are completely independent of customers, and do not have a volumetric element (except for losses). These calculation methodologies can sit alongside a VNM system, but are not linked to it in any way.

6.2 PROS AND CONS OF CALCULATION METHODOLOGIES

Table 10: Pros and cons of VNM Credit calculation methods

	Advantages	Disadvantages
Volumetric TOU	Pre-determined and universally applicable (if applied as Distributed Energy Credit)	Most data intensive. Complex technology specific approach which may unduly disadvantage some technologies. No incentive for DG to improve capacity support. Independent of where customer is situated, so may not achieve the same distribution efficiencies. Lower value given to DG (may be because less cost reflective). If delinked from customer, may require technical options to ensure cost reflective pricing (to monitor and/or prevent exports to upstream network levels).
Existing Tariff	Most defensively cost reflective, as directly based on current network tariffs. Provides incentive to DG to improve capacity support.	More intuitive to implement in a VNM system with customers linked to DG, but complication of whose network charge is it based on – generator or consumer? If existing tariffs are not adequately cost reflective (e.g. not strongly weighted enough towards capacity payment), this would 'over credit' DG to the same extent.
Capacity Payment	May appeal to networks. Strong incentive to DG to provide capacity when required.	Not reflective of current tariff structures. Can only be credited to generator. Disregards any volumetric impact on network. Much less predictable for variable DG than volumetric payments, as takes 'all or nothing' approach.
Locational	Most economically	Short-term focus does not reward long-term load growth

Constraint	efficient in the short-medium term. Could be combined with other methods to provide short-medium term targeted network support	reduction and reduction of flow through higher network levels. Will only be applicable in a minority of locations. Requires locational network marginal cost calculations to be frequently updated, and case-by-case network engagement. Value will change year by year, and cease if the network is augmented, or the DNSP enters network support contract.

Table 10 shows the pros and cons of the four calculation methods. The two capacity based methods (capacity payment and locational constraint) are restrictive in how they may be applied, and it is not recommended to take these forward as the sole methodology. However, networks should be allowed to apply higher locational incentives in constrained areas with very high avoidable cost values. This could be applied to any of the three non-locational calculation methods assessed. In effect, these methods would provide a “benchmark minimum” and higher values could be applied where relevant.

Both the Volumetric TOU and Existing Tariff methods have advantages, and may be used within either a VNM or DEC framework, although the most obvious combinations are the Volumetric TOU method with DEC and the Existing Tariff method with VNM. The key advantages of each are that the Existing Tariff, particularly combined with VNM, is most obviously cost reflective (to the extent that the tariff is cost-reflective), while the Volumetric TOU reduces operational complexity.

6.3 RECOMMENDATIONS AND NEXT STEPS

The decision between a generally available Distributed Energy Credit and a VNM system will have a significant impact on the development of DG in Australia. However, the availability of credits through either system could significantly improve the business case for DG, while providing a revenue stream for networks on DG exports. The potentially greater cost reflectiveness of VNM is an advantage; however, a decision to pursue one calculation method or the other may be informed by broader examination of the business case outcomes for the two methods. This would include the energy costs and benefits, as looking at network costs alone is insufficient to assess the pros and cons of each for different stakeholders. This should be considered for inclusion in Stage 2 of the project.

The methodologies developed in Stage 1 for calculating the VNM Credit offer viable alternatives to value DG; in particular the TOU and the Existing Tariff methodologies offer flexible and potentially robust means to value the network services DG can offer. This initial assessment demonstrates that it is possible to develop methods for valuing the network services that should not unduly disbenefit any party.

In order to arrive at a preferred methodology, ISF recommends the following work to be undertaken in later stages of the project:[29]

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[29] The project has 3 stages. This report forms the final deliverable of Stage 1; Stage 2 involves selection, refinement and more robust application of the calculation methodology and confirmation of Rule Change requirements; Stage 3 involves preparing any relevant Rule Change documentation.

1. Take forward the Volumetric TOU and Existing Tariff methodologies into Stage 2 of the analysis, as well as consideration of a preferred overarching VNM or DEC system.
2. Undertake consultation with network businesses to obtain buy-in regarding the general approach, specific methodological considerations, and obtaining specific cost data. Essential Energy and Ergon Energy are two key parties with whom this could be taken forward, based on the consultation groundwork undertaken during Stage 1. This will likely need to include discussion of issues such as:
    a. How to deal with network areas with flat or negative load growth.
    b. How to deal with 'generation dominated' network areas where reverse electrons flows may occur.
    c. Whether VNM Credit should account for bringing forward the avoided cost of network augmentation.
    d. Where the generator or customer network tariffs used for the Existing Tariff method.
    e. Conditions surrounding the calculation of F-Factors in the Volumetric TOU method.
3. In Scoping Stage 2 consider the inclusion of the following issues in the analysis:
    a. The impact of energy cost effects (as addition to network cost effects) on stakeholder outcomes.
    b. Analysis of "behind the meter use" in terms of stakeholder revenues and outcomes for non-participant consumers.
4. Make contact with consultants undertaking the concurrent Victorian 'Valuing DG' project to seek alignment of approaches given similarities in the project goals and potential for inconsistent recommendations.
5. Engage with key industry stakeholders to:
    a. Establish stakeholder positions on key design issues to assist in defining a preferred methodology and transaction pathway.
    b. Refine the regulatory uncertainties surrounding transaction complexities of the proposed models.
6. Develop final details of the proposal, and examine the metering, retail and network regulatory requirements to confirm the status of any required Rule Change/s associated with the preferred VNM/DEC framework and market transaction pathway.

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APPENDIX 1: INPUT DATA

Table 11: Peak Demand, Revenue Data and Source

NSP	Variable	Data	Year	Source
Essential Energy	Peak demand (MW)	2,681	2013/14 (forecast)	AER Final New South Wales distribution determination 2009–10 to 2013–14 Table 6.1 p.83
	Revenue ($m/a)	1,474	2013/14 (forecast)	Country Energy PTRM Forecast Revenue 2009-10 (Country Energy PTRM - revised by Tribunal_0.xls). Available at http://www.aer.gov.au/node/13274
Ausgrid	Peak demand (MW)	6,679	2013/14 (forecast)	AER Final New South Wales distribution determination 2009–10 to 2013–14 Table 6.4 p.86
	Revenue ($m/a)	2,076	2013/14 (forecast)	Energy Australia PTRM Forecast Revenue 2009-10 (EnergyAustralia distribution PTRM - revised by Tribunal.xls. Available at http://www.aer.gov.au/node/13151
Transgrid	Peak demand (MW)	13,946	2012/13	Transgrid Annual Planning Report 2013, p29
	Revenue ($m/a)	986	2012/13	Transgrid Annual Report 2013, p41

Table 12: Electricity Price assumptions – Large Business Trigeneration, Ausgrid

	Retail charges ex. GST	Network charges ex. GST	
Peak (2-8pm weekdays)	20.7	11.3	c/kWh
Shoulder (7am-2pm, 8pm-10pm, weekdays)	14.1	5.6	c/kWh
Off-Peak (remainder)	9.6	2.9	c/kWh
Capacity Charge	338.3	338.3	$/MVA/day
Daily Supply Charge		41.0	$/day

Table 13: Electricity Price assumptions – Large Business for Solar PV, Essential Energy

	Retail charges ex. GST	Network charges ex. GST	
Peak (7-9am, 6-8pm weekdays)	26.7	17.2	c/kWh
Shoulder (9am-6pm weekdays)	25.8	17.2	c/kWh
Off-Peak (remainder)	13.1	6.4	c/kWh
Capacity Charge	614.6	614.6	$/MVA/day
Daily Supply Charge		13.6	$/day

APPENDIX 2: ADDITIONAL MODELLING RESULTS

Table 14: VNM Credit values by each methodology (Essential network), and typical network charges

METHODOLOGY	VNM CREDIT RATES/ EXPORT VALUES						TYPICAL NETWORK CHARGES [4]	
	Volumetric TOU (trigeneration) [1]	Volumetric TOU (solar PV) [1]	Existing Tariff	Capacity Payment	Locational Constraint		Large customer	Small customer
DG CONNECTED AT LV SYSTEM								
PEAK Value c/kWh	**18.4**	**5.7**	**12.6**	**-**	-		17.2	17.5
SHOULDER c/kWh	**1.5**	**0.5**	**12.6**	**-**	-		17.2	17.2
OFF PEAK c/kWh	**0.2**	**0.1**	**4.7**	**-**	-		6.4	8.1
Capacity Payment $/MVA/day	**-**	**-**	**615[2]**	**1,105**	**Zero or 1,370 [3]**		615	615
DG CONNECTED AT HV SYSTEM								
PEAK Value c/kWh	**11.3**	**3.5**	**7.5**	**-**	-		17.2	17.5
SHOULDER c/kWh	**0.6**	**0.2**	**7.5**	**-**	-		17.2	17.2
OFF PEAK c/kWh	**0.0**	**0.0**	**2.8**	**-**	-		6.4	8.1
Capacity Payment $/MVA/day	**-**	**-**	**615 [2]**	**629**	**[3]**		615	615

Notes:
[1] TOU rates are technology specific, while the other methods are not.
[2] Capacity charges for the Existing Tariff method are set at the tariff the customer pays, so the base rate will always equal the network capacity charge
[3]The locational VNM Credit will be zero in areas which are not grid constrained, and the magnitude will depend on planned augmentation.
[4]Large customer rates are Essential large business and small customer rates are Essential small business.

Figure 20: VNM Credit value comparison by methodology and generator types