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Modelling the Value of Local Generation Network Credits

Prepared for the Australian Energy Market Commission

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Executive Summary

The AEMC received a request from the City of Sydney, Total Environment Centre and the Property Council of Australia to implement a Local Generation Network Credit (LGNC)[1] scheme, which would require that Distribution Network Service Providers (DNSPs) pay embedded generators[2] (within the distribution system) for the energy exported. The LGNC would reflect the benefits that embedded generation would provide to DNSPs in terms of reducing future operating and capital costs.

In response to the rule change application the AEMC had commenced a consultation process and appointed Marsden Jacob Associates (Marsden Jacob) to undertake economic modelling to determine the potential value of LGNCs and estimate the total payments that DNSPs would make to embedded generators should the proposal be made into a rule.

Conceptually, there are a number of benefits and costs associated with increased embedded generation on the distribution network. This includes:

- Reduced CAPEX and OPEX that results from a reduction in peak demand on the distribution network;
- Increased costs on the distribution system (e.g. fault levels etc.), especially if the penetration of embedded generation is high;
- Reduced transmission CAPEX and OPEX;
- Reduced wholesale energy costs;
- Changed requirements for voltage and frequency support (transmission and distribution).

The rule change request relates only to network (i.e. distribution and transmission) CAPEX and OPEX savings. As such, this study focuses on estimating a value for LGNCs that reflects such potential savings.

The major driver of network costs (especially CAPEX) is peak demand growth (kVA). For this study, we have calculated the avoided costs of peak demand growth on the basis of:

- The long run marginal cost (LRMC) estimates of meeting peak network load ($/kVA) that DNSPs are required to provide to the Australian Energy Regulator (AER) in their Tariff Structure Statements; plus
- Locational Transmission Use of System (TUOS) charges.

Given that the major driver of network costs is peak demand growth (kVA), significant benefits will only arise if the net exports[3] of embedded generation are coincident with peak demands on networks. We have developed an algorithm (referred to as the Annual Peak Demand Credit Method) for allocating avoided costs to each embedded generator type based on the net exports of these generators that contribute to reducing peak demand supplied by the network. Under this method, we calculate an annual peak demand credit ($/kVA/annum) for each generator type (by DNSP pricing regions) and apply the credit to the average of net exports of embedded generators during the peak demand period for the network.

1 The abbreviation LGNCs and term network credits are used interchangeably in this document.

2 Embedded generation is defined as any generating unit that has the potential to export power into the distribution. Can include generators co-located at a customer premise (e.g. household PV).

3 Net of customer load for co-located generators.

The peak demand period within a network will vary depending upon the composition of customers connected to downstream network assets. Some examples are outlined below:

- The peak period for a zone substation with mainly residential customers connected to LV assets in a region will typically be between 1 PM to 7 PM on a summer weekday day.
- In a zone substation area with a high penetration of residential PV (> 20%), peak demand can occur later in the afternoon and in the evening (4 PM to 9 PM).
- In a zone substation with mainly commercial customers connected, peak demand can occur between 10 AM and 5 PM (i.e. commercial trading hours), typically in summer months due to business requirements for air conditioning.

The importance of establishing a peak period within a DNSP supply region is critical to this study since it will be determine the importance of each embedded generation type in being able to reduce peak demand. For example, a network that typically experiences peak demands between 4 PM and 9 PM will not benefit significantly from the installation of more PV systems since the output of these systems are reduced substantially after 5 PM. Whereas, a network that has peak demands during the day, will benefit from the increased penetration of either residential or commercial PV systems.

DNSP’s typically have different peak periods for residential and business customers. This is a valid practice since residential customers will typically be connected to a zone substation that has predominantly residential customers and the load characteristics of that zone substation will be residential in nature (i.e. peaking on a summer weekday in late afternoons/early evening). On the other hand, many business customers will typically be connected to zone substations that has predominantly business customers, where the electricity load will typically peak on a summer’s weekday between 10.00 AM and 5 PM.

The limitation of the above pricing practices of DNSP’s is that it doesn’t capture the benefit that (say) a residential PV system could have in helping to reduce peak demand (10 AM to 4 PM) in a region which has predominantly commercial customers. However, the costs of implementing peak pricing periods at the sub-station level to capture these benefits are likely to expensive and difficult for customers to understand.

For the purposes of this study, we have used the peak demand periods that DNSP’s have stated in their Tariff Structure Statements to determine the value of network credits. In our view, the peak periods reasonably align with actual peak periods for commercial and residential customers in each DNSP supply area. However, it should be noted that these peak demand period definitions are likely to exceed the peak periods that network planners would use in determining the required investment in network capacity to meet peak load. This implies that network credit values could potentially be over or under valued in certain circumstances.

For co-located generators, we have determined average net exports assuming the customer load level is at the 10 per cent Probability of Exceedance (PoE). That is, the load in peak periods, on which the level of embedded generator export is calculated, is based on the top 10% of actual load data that we obtained for residential and commercial customers. In our view this is representative of the basis of network planning and the level of exports that would impact network development.

We note the following:

- That the benefits provided by any individual embedded generator would depend on the level of exported energy at peak time. The analysis presented in this report is static and assumes a linear relationship between exports and potential benefits; and

- Total estimated payments can be very different from the true network cost reductions brought about by embedded generation. Even the best LRMC calculations cannot account for practical constraints or reliability obligations that may mean embedded generation cannot replace network investment in certain circumstances.

Applying this method to the number and type of embedded generators in each DNSP supply area, the analysis shows that:

- The annual payments made by all DNSPs in the NEM would be $50.14 M to embedded generators;
- About 73.2% of total payments will be paid to households with PV systems (see detailed summary of payments in Table 9 in Chapter 3). If households with PV systems were excluded from receiving credits for exported energy, the total payment would be $13.44M.

Some examples of annual payments at the installation level include the following:

- Households with PV – for a customer with a 4 kW PV system, annual credit payments will be less than $50 per annum in most DNSP supply areas.
- Commercial with PV – for a customer with a 20 kW PV system annual credit payments will be less than $60 per annum in most DNSP supply areas. In Northern Queensland (West) payments of $580 per annum could be expected.
- Distribution Solar – for a 200 kW system, payments range from $2,300 per annum in SA/Victoria, up to ~$6,700 per annum in North QLD. Payments in country NSW are around $2,300 per annum.
- Distribution Wind –for a 1 MW System, payments range from $11-15,000 in Victoria, $28,000 in country NSW and $27,000 in Northern Queensland.
- Cogeneration – for a 5 MW System, payments range from around $105,000 in NSW, $129,000 in South Australia and ~$200,000 per annum in rural NSW and Northern Queensland.

In conclusion, payments to residential and commercial customers with PV are not significant since net exports are low at peak times on the network. For residential PV this is due to the fact that solar output is low at typical peak times on the network (4 PM to 9 PM), while the output of commercial PV systems is high when the load of these customers is high (10 AM to 5 PM).

The Annual Peak Demand Credit Method used to determine annual credit value may not be suitable for setting network credits in practice, since it is based on annual demand charges which are not used in practice by DNSPs for billing. It would be expected that DNSP's would typically establish network credit prices on the basis of energy prices (c/kWh), and monthly demand charges ($/kW/day), or some combination of both.

Once a renewable energy generator is installed, the production trace of the generator is usually invariant with regard to the network credit price structure (or retail tariff structure). However, owners of embedded generation (including renewables) can influence net generation output in the following ways:

- By placing PV systems on the western side of buildings to maximise the output in the late afternoon which may better coincide with the peak demand of network systems (especially those with a high percentage of PV systems in residential areas);
- Locating a wind farm in a region that allows the unit to produce more output during the day, rather than overnight, which is more likely to be coincident with network peak demand;

- Residential and commercial customer reducing load at peak times in order to maximise net exports from their PV systems;
- Customers investing in battery storage with a PV system so that they can recharge the battery at non-peak times (morning period) and discharge the battery at peak times on the network (in the late afternoon and early evening);
- Cogen/trigeneration are semi-dispatchable generation and could increase output at peak times.

There is sufficient prima facie evidence to suggest that the design, placement, sizing and net exports (minus the co-located load) of embedded generators could be influenced by the price structure of the network credits. However, this is only one of many considerations that could influence the design and placement of embedded generation (e.g. retail tariff structure, number of small-scale technology credits, installed cost of the PV system etc.).

For the purposes of this study, we have designed a pricing structure for network credits that could be applied by DNSP’s in practice (referred to as the Monthly Peak Credit Method). Under this method, peak energy or peak demand credits (whichever is applicable) are applied on a monthly basis. Peak demand periods are consistent with network pricing parameters outlined by DNSPs in their Tariff Structure Statements. Under this method, there are no credits provided in shoulder or off peak periods.

1. Purpose of the Study

1.1 Introduction

The AEMC received a request from the City of Sydney, Total Environment Centre and the Property Council of Australia to implement a LGNC scheme, which would require that DNSPs pay embedded generators (within the distribution system) for the energy exported. The LGNC would reflect the benefits that embedded generation would provide to DNSPs in terms of reducing future operating and capital costs.

In response to the rule change application the AEMC had commenced a consultation process and appointed Marsden Jacob to undertake economic modelling to determine the potential value of LGNCs and estimate the total payments that DNSPs would make to embedded generators should the proposal be made into a rule.

The summary terms of reference for this study is as follows:

- Determine the value of an LGNC that would be paid to owners of embedded generators by each DNSP in the NEM. This should reflect economic concepts of long run marginal cost and take into account the network charging practices of DNSPs;
- Determine the total LGNC payments for a 12 month period for various embedded generation types;
- Determine the total payments LGNC payments made by each DNSP (for 12 months).

The detailed terms of reference for this study is provided in Annexure 1.

1.2 Study Outline

For the purposes of this study an embedded generator is defined as any generating unit that has the potential to export power directly into the distribution network. That is, a generator can be co-located at a customer's premises, where potential generator exports are limited by the level of the customer's load, or is connected directly to the distribution network at various voltage levels. Examples of co-located generation include rooftop PV systems for both residential and commercial customers, as well as cogeneration and trigeneration facilities utilised by both commercial and industrial customers. Directly connected generation can include diesel generators[4], geothermal, wind and solar farms.

As outlined in the terms of reference for this study, Marsden Jacob focused on the following embedded generation types:

- Household rooftop solar PV without battery storage;
- Household rooftop solar PV with battery storage;
- Commercial property solar PV;
- Distribution-connected solar PV farm;
- Distribution-connected wind farm;

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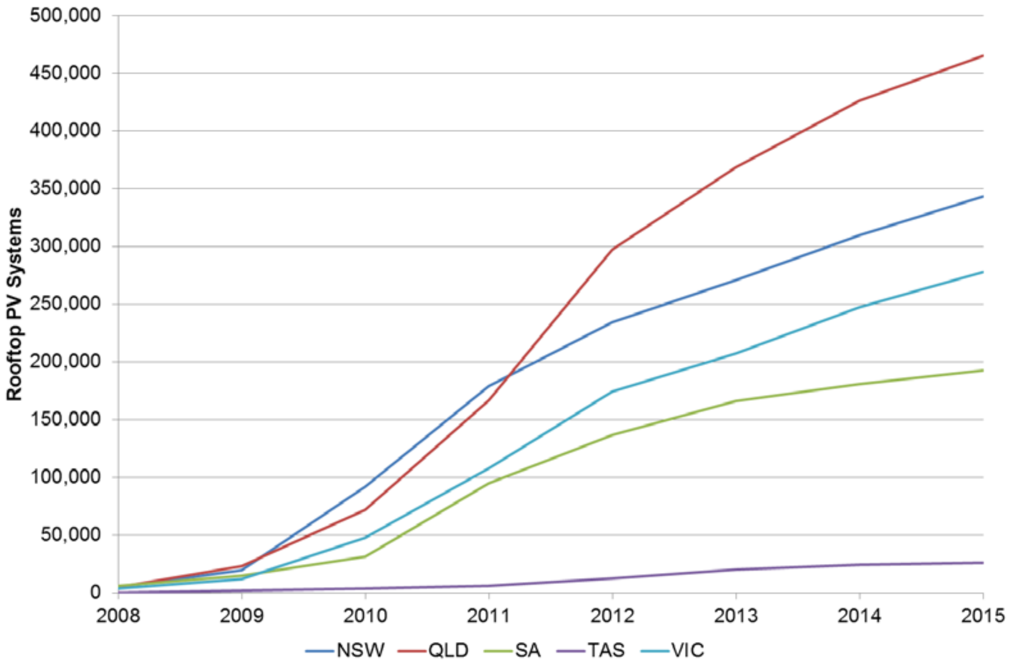
4 Diesel generators are very expensive to operate and are usually used in a standby role unless the customer has contracted to provide this service to a network business or retailer or is using it for risk management purposes. For those reasons, diesel generation is not modelled as part of this study.

- Distribution-connected geothermal plant; and
- Cogeneration or trigeneration facility.

The increased uptake of embedded generation in electricity markets around Australia is a result of a number of factors which includes: customers attempting to decrease energy expenses in the face of rising retail electricity prices; Commonwealth Government incentives for both small and large scale renewable energy technologies[5]; and technological improvements that have lowered the cost of distributed generation. Further technological innovations are likely to improve the efficiency and decrease the costs of battery storage over the next 5 to 10 years, which could result in battery storage being combined with intermittent generation to provide power, either to the customer or the grid, on a more continuous basis.

The rising penetration of Rooftop PV Systems in various NEM jurisdictions is shown in Figure 1.

Figure 1: Rooftop PV Systems in NEM States



Source: MJA from data provided by the Clean Energy Regulator

The increase in the penetration of embedded generation is transforming the electricity sector in Australia and has the potential to disrupt the business models of network service providers, retailers and generators, which have primarily been based on continued growth in electricity sales (MWh) and a heavy reliance on energy revenue (e.g. c/kWh). However, the continued take-up of embedded generation also has the potential to increase the overall efficiency of the electricity value chain.

The advent of embedded generation (in conjunction with battery storage) has the potential to reduce peak demand in both networks and wholesale markets. Peak demand has always been a major driver of investment in networks (e.g. substation transformers etc.), and in the past considerable investment in generation peaking capacity in the wholesale market has been made in order to only deal with demand that may occur for only several hours a year. Embedded generation helps to reduce or eliminate these peaks in network customer demand (more behind

5 Large-scale Renewable Energy Target (LRET) Scheme and the Small-Scale Renewable Energy Scheme (SRES).

the meter consumption) and increase the overall efficiency of the electricity supply network (i.e. reduce need for investment to meet peak demand).

The Rule Change request currently being considered by the AEMC wants to capture the potential net benefits of embedded generation for electricity networks in NEM states. By determining the value of these net benefits and establishing prices (or credits) for the export of power to the grid, there is the potential for DNSPs to encourage the efficient uptake of embedded generation within their relevant supply regions. For example, in regions of the network where there are constraints, DNSPs could use LGNCs to encourage the uptake of embedded generation as a substitute for more costly upgrades of the network. In other regions of the network where there is spare capacity, DNSPs could set LGNC prices at low levels that balance the value of exported energy at peak time with the impact this would have to future network expenditure.

The Rule Change request is focused on the network benefits (or value) potentially offered by embedded generation, and not the wholesale, social or environmental benefits that could arise. The potential network benefits that embedded generation can provide are outlined in ***Chapter 2.2*** of this report.

Given that the major driver of network costs is peak demand growth (kVA), significant benefits will only arise if the net exports of embedded generation are coincident with peak demands on networks. We have developed an algorithm (referred to as the Annual Peak Demand Credit Method)[6] for allocating avoided costs to each embedded generator type based on the capacity (kW) and net exports of these generators. This method is outlined in ***Chapter 3.1*** of this report.

Having determined the value of an LGNC and the appropriate pricing structure of the network credit, the next step is to determine the likely profile of electricity exports provided by each embedded generation type over a 12 month period (especially at the time of network system peak).

For co-located generation, this requires understanding both the consumption pattern of residential and commercial loads, and the sizing (kW output) and generation trace of various embedded generation types. ***Chapter 3.3*** and **Annexure *2*** outlines both the methods and the data sources that were used to develop customer load profiles and generation traces that are necessary to determine co-located embedded generation exports.

For embedded generation that is directly connected to the distribution network, generation output is based on generation traces and actual wholesale market data provided by the Australian Energy Market Operator (AEMO). The data sources are provided in ***Chapter 3.3 and Annexure 2. Chapter 3.4*** provides a summary of LGNC values on an annual basis by each DNSP and embedded generation type.

LGNCs are in effect a '*negative network tariff*', and create a new payment stream between DNSPs and owners of embedded generators. The way in which the LGNC is structured (i.e. tariff design) and metered (gross versus net metering) are important in determining the efficient take-up and operation of embedded generation. ***Chapter 4*** outlines a practical framework for setting network credits.

Chapter 5 comments on the limitations of the modelling approach, while ***Chapter 6*** presents a case study on how the introduction of the network credit can impact the economics of PV systems and battery storage in various DNSP supply areas.

6 Consideration of any environmental or social impacts of embedded generation are outside of the scope of this report.

2. Methodology

2.1 Conceptual Value of Embedded Generation

Conceptually, the value of a LGNC should be based on the networks costs that are avoided by having embedded generation connected to the distribution system. This involves estimating the change in future operating and capital costs under two scenarios:

- Base Case – No additional embedded generation is installed in a distribution area;
- Alternative Case – Additional embedded generation is installed in a distribution area.

While there are likely to be differences in operating costs and reductions in network losses[7], the most significant reduction will likely result from a reduction in future distribution investment that results from a decrease in peak demand (kVA) in each distribution area. In this case, the benefits of embedded generation will be greater in distribution areas that have high demand growth (e.g. newer suburbs) or regions that have old infrastructure that needs to be replaced (e.g. rural areas).

Table 1 below provides a summary of the conceptual network costs and benefits that can arise from embedded generation and the source of those benefits and costs.

Table 1: Conceptual Network Benefits and Costs of Embedded Generation for this Study[8]

Benefit/Costs	Source
• Reduced costs on the distribution system: - Deferred augmentation of the network (CAPEX); - Downsizing of expenditure on network assets (e.g. transformers); - Avoided distribution OPEX	• Reduction in peak demand (kVA) on the distribution system • Will vary with the voltage level that an embedded generator is connected to on the network due to line losses. For example, embedded generation co-located with a load will reduce low voltage, high voltage and sub-transmission network costs. A high voltage connected customer will only reduce sub-transmissions costs.
• Increased costs on the distribution system due to: - Accommodating two-way flow of power; - Increased fault levels - Need for voltage stability	• Increased peak demand (kVA) on the distribution system due to the need to accommodate local generation. • Generally, only applicable if the penetration of embedded generation is high relative to demand and/or the condition of network assets in a particular part of the network.
• Reduced Transmission OPEX and CAPEX	• Reduction in peak demand (kW) at the zone substation (connection point between Transmission and Distribution Systems)

7 Transmission losses impact the amount of generation needed and this is not relevant to the analysis presented in this report.

8 Modified version of the conceptual approach developed by Langham, E. Rutovitz, J. & McIntosh, L., (2015), *Towards a method to calculate a local network credit.*

	• Saving will also vary with where in the network (e.g. voltage level) the embedded generator is connected due to line losses.

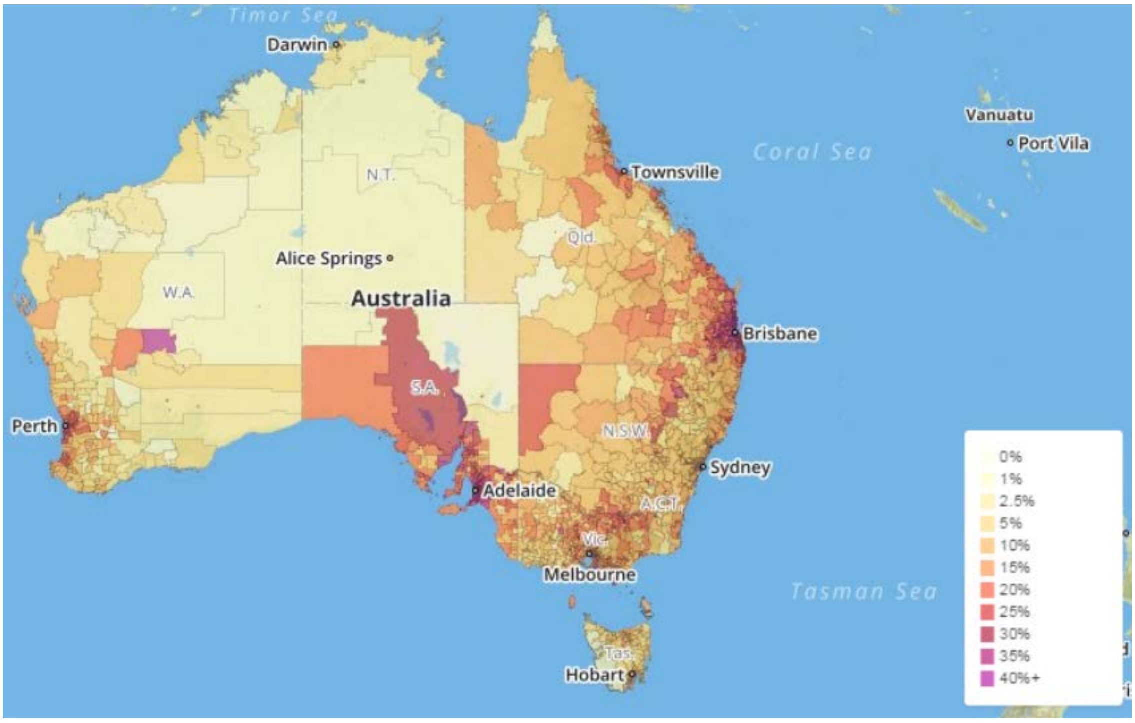
Other benefits and costs, such as reduced wholesale energy costs and changed requirements for voltage and frequency support that can arise with embedded generation, are not considered in this study.

In conclusion, it is likely that the major benefits of embedded generation are the reduction in demand related investment in both the transmission and distribution system in areas where embedded generation penetration is not high. If embedded generation penetration is high relative to demand, then embedded generation itself may drive investment in the network.

The penetration of household PV (i.e. PV systems installed as % of total dwellings) varies considerably between states and regions in the NEM. While the penetration of rooftop solar PV is around 16% across Australia, solar PV penetration is 25% and 24% in South Australia and Queensland respectively.[9] The penetration rates within postcodes can be as high as 64-65% in some areas (e.g. 65% - Angle Vale (SA), 64% - The Ponds (NSW), 58% - Elimbah (QLD)).[10] Queensland and South Australia have 130 and 149 postcodes respectively with household PV penetration rates exceeding 30%.[11] It is likely that in these regions, PV exports could be driving peak investment in the distribution network.

Notwithstanding those postcodes with high rooftop penetration, most postcodes in Australia have modest PV penetrations as illustrated by the following PV penetration heat map.

Figure 2: Rooftop Penetration Heat Map, by Local Government Area



Source: Australian PV Institute (2014), National Survey Report of PV Power Applications in Australia

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9 ESAA Solar Report, December 2015

10 ESAA Solar Report, September 2015

11 ibid

Due to line losses, the benefits will be higher the further 'downstream' the embedded generator is in the network. Co-location of generation and loads will provide the largest benefits in terms of network investment.

The critical issue for this study is to quantify the conceptual benefits and costs of embedded generation so that the value of an LGNC can be determined in practice.

2.2 Determining the Value of Embedded Generation in practice

2.2.1 Long Run Marginal Cost of Network Services

Long run marginal cost is a measure that can be used to calculate the reduction in network costs that results from reductions in peak demand that arise from the installation of embedded generation. The AEMC has mandated that DNSPs use an estimate of LRMC in setting network prices:[12]

"Each network tariff must be based on the long run marginal cost of providing the service."

There are a variety of methodologies which can be used to calculate the LRMC of network services, including the Average Incremental Cost methodology (AIC) and the Perturbation or 'Turvey' methodology, amongst others.[13]

It is our understanding that DNSPs typically use the Average Incremental Cost methodology in determining the LRMC of providing network services. The key features of this approach are outlined below.

The AIC methodology estimates LRMC as the average change in future operating costs and capital expenditure resulting from a change in peak demand. Typically DNSPs calculate LRMC over 10 years in the future and discount both costs and the cumulative change in peak demand to calculate a current day estimate of LRMC. The formula used to calculate LRMC is shown below.

$$LRMC\ (\frac{\$}{kVA}) = \frac{NPV\ of\ demand\ driven\ augmentation\ and\ operating\ costs\ (\$M)}{NPV\ of\ cumulative\ growth\ in\ peak\ demand\ (kVA)}$$

It should be noted that this method only approximates *'true'* marginal cost changes. When changes in CAPEX are smooth, the AIC method will be a close reflection of marginal costs. However, if CAPEX is lumpy, due to significant investment required to reduce network constraints, then this method will under estimate marginal costs. Equally the AIC approach will overestimate the LRMC when the network is not close to being constrained.

LRMC estimates (by voltage level and customer class) are published by DNSPs in their Tariff Structure Statements (TSS) and could be used to estimate the capital and operating cost savings that a reduction in peak demand from embedded generators could deliver (typically $/kVA), appreciating the above mentioned limitations with this approach.

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12 AEMC (2014), *Distribution Network Pricing Arrangements, Rule Determination*, 27 November 2014, Sydney

13 For a detailed discussion on various methods used to estimate LRMC see NERA Economic Consulting (2014), *Economic Concepts for Pricing Electricity Network Services*, A Report for the Australian Energy Market Commission, 21 July 2014.

While DNSPs are required to publish LRMCs for distribution services, there is currently no requirement for Transmission Network Service Providers (TNSPs) to estimate and provide LRMC's for each connection point (i.e. zone substation level).

Currently TNSPs utilise the current Cost Reflective Network Pricing (CRNP) approach to set transmission tariffs. In its Revenue Proposal to the AER, Powerlink stated[14]:

"To seek a change from the current CRNP (backward looking) approach to establish asset values to a Long Run Marginal Cost (LRMC or forward looking) approach. Powerlink acknowledged that this was not permitted under the current Rules and hence could not be proposed in its Pricing Methodology. However, it may be considered as a potential Rule change proposal;"

Marsden Jacob is not aware of any TNSPs providing LRMC estimates in their revenue proposals.

Currently TNSPs have the following charging structures for transmission services[15].

- Locational Transmission Use of System Charges (TUOS). In Victoria, the locational TUOS charge is based on average maximum demand and is reflective of the long run marginal cost of transmission at each connection point. In other jurisdictions, such as NSW/ACT, the TUOS charge can include a fixed exit charge ($/day) and a demand charge ($/kW/month).
- Common service charges which typically recover the cost of planning and operating the network such as control buildings, protection systems, easement and land tax etc. The common service price is either an energy price or a capacity price, each of which has a common value across all locations.
- Non-locational charges recover the balance of annual revenue requirements for provision of the shared transmission network and mainly relate to overhead and financing costs. The non-locational price is either an energy price or a capacity price, each of which have a common value across all locations.

Based on the current pricing structure of TNSPs, the only costs that can be avoided and attributed to an embedded generator on the distribution network are the locational TUOS demand charge ($/kW/month). This can be used as a proxy for the avoided costs resulting from an embedded generator.

2.2.2 Treatment of Other Costs

Given the current low penetration of embedded generation in most regions and the locationally averaged nature of distribution prices, it is unlikely that additional embedded generation will increase network costs in most regions in the short term. As such, this study does not attempt to assess the value of LGNCs in situations where embedded generation imposes net costs on the network.

14 Powerlink, *2018-22 Powerlink Queensland Revenue Proposal*, Submitted to the AER, p.124.

15 Refer to AEMO (2015), *Electricity Transmission Use of System Prices*, 1 July 2015 to 30 June 2016, For the National Electricity Market, Published May 2015.

2.2.3 Network Benefit/Cost Summary

Table 2 provides a summary of how we shall treat the benefits and costs of embedded generation in this study.

Table 2: Study treatment of embedded generation network benefits and costs

Benefit/Costs	Method for Estimating the Benefit/Cost
• Reduced costs on the distribution system:	• DNSP LRMC estimates by voltage
• Increased costs on the distribution system.	• Given the low penetration of embedded generation in most regions, assumed to be zero for this study.
• Reduced Transmission OPEX and CAPEX	• TNSP locational TUOS demand charges.

3. Estimating the value of LGNCs

3.1 Designing a LGNC Price Structure for Cost Attribution

In order to attribute the potential benefits of network credits for different embedded generation types, we need to develop an algorithm for allocating potential network cost savings to each embedded generator type based on the net exports of these generators.

As outlined in section 2.1, the main benefit of embedded generation for a DNSP is to reduce peak demand costs ($/kVA or $/kW) in the network. This suggests that given that the main driver for network savings (or costs) are reductions in peak demand, it would be appropriate to apportion costs on the basis of demand charges. Our approach to determine the value of LGNC's in this study is to develop a 'cost-reflective' network credit that is based on demand charges and apply this to the net exports of each embedded generator type.

While the above approach will be used to determine the value of LGNC's, this is not necessarily how DNSP's would be required to price in practice. Chapter 4 discusses factors that impact the choice of network credit pricing methods in practice.

In order to attribute potential benefits to embedded generators we have developed an algorithm, referred to as the *Annual Peak Demand Credit Method*, for allocating avoided costs to each embedded generator type based on the net exports of these generators that contribute to reducing peak demand supplied by the network. Under this method, we calculate an annual peak demand credit ($/kVA/annum) for each generator type (by DNSP pricing regions) and apply the credit to the average of net exports of embedded generators during the peak demand period for the network.

In addition, for co-located generators, we are only concerned with net exports on days when the network is likely to experience a peak demand event, which implies that customer consumption is also likely to be higher than typical levels due to increased demand for air conditioning (or space heating for winter peaking networks). For this study, we determined the net exports at that customer load level that has a 10 per cent Probability of Exceedance (PoE). This is the load in peak periods based on the top 10% of actual load data obtained for residential and commercial customers (data sources outlined in Chapter 3.3).

The advantage of the Annual Peak Demand Credit Method is that it more closely reflects the 'true' value of a LGNC. That is, the credit is based on the generation output in those periods in which peak demand on the network is highly likely.

While this method is useful for determining the value of a network credit, it may not necessarily be practical to implement. This approach is unlikely to be used by DNSPs to calculate payments to embedded generators since it requires calculating average peak demand over a number of months (e.g. November to March) before bills can be calculated based on the annualised LRMC estimates.[16] This may not be consistent with the billing method and cycles of DNSPs. If this approach was used in practice, it would most likely require the use of 12 monthly rolling peak demand estimates. That is, the LGNC payment for this year would be based on the previous 12 months of net generation exported at peak demand times (similar to the way that current Reserve Capacity payments for retailers and loads are calculated in the Wholesale Electricity Market (WEM) in Western Australia).

[16] This is analogous to the concept of ex post charging outlined by Ergon Energy, Supporting Document: Long Run Marginal Cost, Considerations in Developing Network Tariffs, March 2015.

In Chapter 4 we have developed LGNC tariffs that mirror a DNSP's cost reflective tariffs. The overall level of these LGNC tariffs is based on the value of credits estimated using the Annual Peak Demand Credit Method.

3.2 Avoided Network Costs

The level of network credits is based on the avoidable network costs that can be provided by an embedded generator. The assessment of avoided costs are based on:

- LRMC estimates (by voltage level or customer class) as outlined in each DNSPs Tariff Structure Statement for 2015-16.
- Locational TUOS demand charge, adjusted for line losses.

These charges were combined to estimate the avoided costs ($/kVA) of embedded generators in each supply region. A simplifying assumption is made that peak demand on the distribution system and the transmission system occurs at the same time so that the two charges can be combined into one demand charge that applies to embedded generators. Our analysis of substation data and peaks in the distribution system for various DNSPs suggests that they are highly correlated.

The charge by customer class (e.g. residential, small business etc.) and voltage level for each DNSP supply region is shown in Table 3. Each DNSP has uniform costs that apply within each supply area, with the exception of Ergon Energy that has three separate pricing regions – East, West and Mt Isa. The use of uniform pricing within a DNSP supply area does limit the accuracy of the analysis. It is likely that within a DNSP supply region, there are network assets that are underutilised, while others are likely to be constrained in the future. Ideally DNSPs should set network credit prices at regional levels to either discourage or encourage the take-up of embedded generation.

Table 3: LRMC - Avoidable Peak Demand Costs by DNSP, $/kVA, 2015-16 values

State	DNSP	Residential PV	Small Business LV	Large Business LV	Large Business HV	Sub-transmission
ACT	Actew AGL	201.93	201.93	201.93	25.35 (a)	16.58 (a)
NSW	AusGrid	164.00	164.00	164.00	53.00	8.00
VIC	CitiPower	94.20	109.90	103.20	67.30	24.80
NSW	Endeavour Energy	129.68	129.68	129.68	25.35	16.58
QLD	Energex	123.66	123.66	123.66	117.73	57.40
QLD	Ergon Energy - East	472.00	472.00	472.00	291.00	50.00
QLD	Ergon Energy - Mt Isa	472.00	472.00	472.00	-	-
QLD	Ergon Energy - West	1,180.00	1,180.00	1,180.00	722.50	125.00
NSW	Essential Energy	292.66	292.66	292.66	153.17	30.10
VIC	Jemena	119.00	105.00	90.00	47.00	47.00
VIC	Powercor	96.60	112.70	109.50	77.00	9.80
SA	SA Power Networks	115.98	115.98	115.98	76.05	34.22
VIC	SP AusNet	88.70	88.70	88.70	24.58	16.08
TAS	TasNetworks	173.01	156.85	85.56	67.49	30.00 (a)
VIC	United Energy	115.32	111.60	124.00	80.00	15.00

Source: DNSP Tariff Structure Statements submitted to the AER in 2015 and 2016.

Notes: (a) Marsden Jacob assumptions given that LRMC values for this network connection level were not published in the relevant DNSP Tariff Structure Statements.

Some observations from Table 3 include the following:

- In most cases LV costs are significantly higher than both HV and Sub-transmission costs in most DNSP supply areas (which is to be expected since LV customers are utilising more network assets). There are exceptions to this:
  - In Queensland LV and HV costs are very similar, which indicates that distance related factors (e.g. low customer density) maybe a major driver of HV costs in that state
  - Two Victorian DNSPs (Powercor and United Energy) have published lower LRMC values for downstream elements (i.e. Residential LV and Large Business LV). Such differences can arise if peak demand growth by Large Business LV customers is driving more investment than required to service Residential LV customers.
- Network costs in Victoria are significantly lower on average than in other jurisdictions due to higher customer density in the Victorian distribution networks;
- The relatively high costs in the supply regions for TasNetworks, Essential Energy and the Ergon Energy reflect lower customer density compared to other DNSPs;
- ActewAGL LRMC's are also significantly higher than for other city based DNSPs (e.g. Ausgrid or CitiPower).

This implies that LGNC prices are likely to be significantly higher in Tasmania, country NSW and northern Queensland than in other states, which provides more incentives for embedded generation to be installed in those regions.

Table 4 provides a summary of the average locational TUOS demand charges that apply to each DNSP on an annual basis (are typically charged monthly). These charge vary considerably, but are typically only around 15% of DNSP avoided costs for LV customers. Hence, the major determinant of network credit levels for LV customers will be avoided DNSP costs in most regions.

Locational TUOS charges will be much more important in determining network credit levels for HV and Sub-transmission connected generators.

Table 4: Locational Transmission Use of System Demand Charges, $/kW, 2015-16

State	DNSP	$/kW/annum
ACT	ActewAGL	26.23
NSW	Ausgrid	37.53
VIC	Citipower	17.94
NSW	Endeavour Energy	17.18
QLD	Energex	20.58
QLD	Ergon Energy - East	34.36
NSW	Ergon Energy - Mt Isa	33.93
VIC	Ergon Energy - West	31.86
NSW	Essential Energy	48.72
VIC	Jemena	32.22
VIC	Powercor	33.35
SA	SA Power Networks	21.96

VIC	SP Ausnet	13.90
TAS	TasNetworks	25.76
VIC	United Energy	17.27

Source: TNSP Published TUOS Charges

Table 5 below shows the assumed connection level and customer class for calculating the potential distribution cost benefits of each embedded generator type in this study. This is based on our understanding of the likely network configuration for each embedded generation type. For example, it is assumed that PV systems are co-located with the load for households (and commercial premises). As a result, the relevant LRMC (avoided cost) that is applicable to this embedded generation type is Residential Low Voltage (refer Table 3 above). Similarly, commercial properties with solar PV are also assumed to be LV connected. Distribution-connected generators are all assumed to be connected to HV networks (11 to 22 kV). In effect, cost savings for each embedded generator type commence upstream of the connection level for each embedded generator type.

Table 5: Mapping Embedded Generator Type to DNSP Connection Levels

Embedded Generation Type	Potential Benefits begin at this Upstream Connection Level
Household rooftop solar PV without battery storage	Residential - LV
Household rooftop solar PV with battery storage	Residential - LV
Commercial property solar PV	Large Business - LV
Distribution-connected solar PV farm	Sub-transmission
Distribution-connected wind farm	Sub-transmission
Distribution-connected geothermal plant	Sub-transmission
Cogeneration or trigeneration facility	Sub-Transmission

3.2.1 Peak Demand Costing Periods

Under this method, we calculate an annual peak demand credit ($/kVA/annum) and apply the credit to the average net exports of embedded generators during the peak demand in each DNSP supply region.

The peak period within a network will vary depending upon the composition of customers connected to the downstream network assets. Some examples are outlined below:

- The peak period for a zone substation with mainly residential customers connected to LV assets in a region will typically be between 1 PM to 7 PM on a summer weekday day.
- In a zone substation area with a high penetration of residential PV (> 20%), peak demand can occur later in the afternoon and in the evening (4 PM to 9 PM).
- In a zone substation with mainly commercial customers connected, peak demand can occur between 10 AM and 5 PM (i.e. commercial trading hours), typically in summer months due to the requirements for air conditioning.
- In a zone substation with a mix of commercial and residential customers, peak demand will typically be between 11 AM and 7 PM on summer weekdays.
- For a zone substation with mainly industrial and commercial customers, demand does not have such a noticeable peak periods (i.e. flat demand).
- Some peak periods occur in winter only or both winter and summer.

Analysis of zone substation data for Northern Queensland and South Australia is provided in Annexure 3. These regions were chosen because of the high proportion of residential and commercial PV that was installed in these regions, which could influence the determination of the relevant peak demand period for this analysis.

The importance of establishing a peak period within a DNSP supply region is critical to this study since it will be determine the importance of each embedded generation type in being able to reduce peak demand. For example, a network that typically experiences peak demands between 4 PM and 9 PM will not benefit significantly from the installation of more PV systems since the output of these systems are reduced substantially after 5 PM. Whereas, a network that has peak demands during the day, will benefit from the increased penetration of either residential or commercial PV systems.

DNSP's typically have different peak periods for residential and business customers. This is a valid practice since residential customers will typically be connected to a zone substation that has predominantly residential customers and the load characteristics of that zone substation will be residential in nature (i.e. peaking on a summer weekday in late afternoons/early evening). On the other hand, many business customers will typically be connected to zone substations that has predominantly business customers, where the electricity load will typically peak on a summer's weekday between 10.00 AM and 5 PM.

The limitation of the above pricing practices of DNSP's is that it doesn't capture the benefit that (say) a residential PV system could have in helping to reduce peak demand (10 AM to 4 PM) in a region which has predominantly commercial customers. However, the costs of implementing peak pricing periods at the sub-station level to capture these benefits are likely to be costly and difficult for customers to understand.

For the purposes of this study, we have used the peak demand periods that DNSP's have stated in their Tariff Structure Statements to determine the value of network credits. In our view, the peak periods reasonably align with actual peak periods for commercial and residential customers in each DNSP supply area. However, it should be noted that these peak demand period definitions are likely to exceed the peak periods that network planners would use in determining the required investment in network capacity to meet peak load. This implies that network credit values could potentially be over or under valued in certain circumstances.

Table 6 provides a summary of the peak demand periods by DNSP that is used to attribute credits to residential PV Systems. While most peak demand periods occur in summer in the late and early evening of working weekdays, some DNSP's define peak periods for every month of the year (e.g. Energex, Actew AGL, Endeavour Energy, Essential Energy and TasNetworks). This is despite the fact that residential customer loads are typically summer peaking (i.e. Energex) or winter peaking (i.e. Essential Energy and TasNetworks) and/or both (i.e. Actew AGL, Endeavour Energy) in each respective DNSP supply area. Some DNSP's have adopted non-seasonal network tariffs to simplify price signals to customers.

Table 6: Residential Peak Demand Periods, by DNSP (local time)

State	DNSP	Peak Demand Period(s)	Day Type	Season(s)	Month(s)
ACT	Actew AGL	7 AM to 9 AM 5 PM to 8 PM	Weekdays	No	All Months
NSW	AusGrid	2 PM to 8 PM	Weekdays	Summer	Nov to Mar
VIC	CitiPower	3 PM to 9 PM	Weekday	Summer	Jan to Mar
NSW	Endeavour Energy	1 PM to 8 PM	Weekdays	No	All Months
QLD	Energex	4 PM to 8 PM	Weekdays	No	All Months
QLD	Ergon Energy - East	3 PM to 9 PM	Weekdays	Summer	Dec to Feb
QLD	Ergon Energy - Mt Isa	3 PM to 9 PM	Weekdays	Summer	Dec to Feb
QLD	Ergon Energy - West	3 PM to 9 PM	Weekdays	Summer	Dec to Feb
NSW	Essential Energy	7 AM to 9 AM 5 PM to 8 PM	Weekdays	No	All Months
VIC	Jemena	3 PM to 9 PM	Weekdays	Summer	Dec to Mar
VIC	Powercor	3 PM to 9 PM	Weekdays	Summer	Dec to Mar
SA	SAPN	4 PM to 9 PM	Weekdays	Summer	Nov to Mar
VIC	SP AusNet	3 PM to 9 PM	Weekdays	Summer	Dec to Mar
TAS	TasNetworks	7 AM to 10 AM 4 PM to 9 PM	Weekdays	No	All Months
VIC	United Energy	3 PM to 9 PM	Weekdays	Summer	Dec to Mar

Source: Marsden Jacob review of DNSP Peak Periods as defined in Tariff Structure Statements.

The peak periods for commercial customers and distribution connected generators are provided below. For most DNSP's, the peak period is 10 AM to 6 or 8 PM. The exceptions are Endeavour Energy (1 PM to 9 PM), SA Power Networks (4 PM to 9 PM), Ausgrid (2 PM to 8 PM) and SP AusNet (3 PM to 7 PM).

Most commercial sub-networks in each DNSP supply area are summer peaking (Nov to Mar), except for the winter peaking systems of TasNetworks, Essential Energy (NSW) and ActewAGL (ACT). However, the latter three DNSP's have not adopted season pricing (as was the case for residential customers). Jemena and Energex both have summer peaking systems but have adopted non-seasonal pricing for business customers. Only Endeavour Energy has both a summer and winter demand peak period for business customers.

Table 7: Peak Demand Periods for Commercial PV and Distribution Connected Generators (local time)

State	DNSP	Peak Demand Period(s)	Day Type	Season	Month(s)
ACT	Actew AGL	10 AM – 6 PM	Weekdays	No	All
NSW	AusGrid	2 PM – 8 PM	Weekdays	Summer	Nov to Mar
VIC	CitiPower	10 AM – 6 PM	Weekdays	Summer	Dec to Mar
NSW	Endeavour Energy	1 PM – 9PM	Weekdays	Summer/Winter	Summer: Nov to Mar Winter: Jun to Aug
QLD	Energex	9 AM – 9PM	Weekdays	No	All
QLD	Ergon Energy - East	10 AM – 8 PM	Weekdays	Summer	Dec to Feb
QLD	Ergon Energy - Mt Isa	10 AM – 8 PM	Weekdays	Summer	Dec to Feb
QLD	Ergon Energy - West	10 AM – 8 PM	Weekdays	Summer	Dec to Feb
NSW	Essential Energy	7 AM – 9 AM & 5 PM - 8 PM	Weekdays	No	All
VIC	Jemena	10 AM – 8 PM	Weekdays	No	All
VIC	Powercor	10 AM – 6 PM	Weekdays	Summer	Nov to Mar
SA	SAPN	4 PM – 9PM	Weekdays	Summer	Nov to Mar
VIC	SP AusNet	3 PM – 7 PM	Weekdays	Summer	Dec to Feb
TAS	TasNetworks	7 AM – 10 AM & 4 PM - 9 PM	Weekdays	No	All
VIC	United Energy	7 AM – 7 PM	Weekdays	Summer	Nov to Mar

Source: Marsden Jacob review of DNSP Peak Periods as defined in Tariff Structure Statements

3.3 Embedded Generation Export Profiles

In order to determine the value of embedded generation to the network, we were required to determine the export traces for embedded generators within each DNSP supply region. This required determining the following:

- The gross generation trace for each embedded generator type (e.g. PV);
- For co-located embedded generators, the customer load profile (e.g. residential versus commercial);
- For co-located embedded generators, calculating the net generation (or exports) by deducting customer load from the gross generation trace (if there is an negative value in an interval then the customer is purchasing energy from the grid);
- For distribution connected embedded generators, assuming that all output is exported to the grid.

Marsden Jacob developed generation traces and customer load profiles for each embedded generation type for each DNSP supply area. The methods used to develop the traces and load profiles, as well as the data sources, are outlined in Annexure 2.

Wherever possible, we developed traces and load profiles based on data from each NEM region and/or DNSP supply area. The sources of data for the development of embedded generation traces and customer load profiles included the following:

- Average PV system size (kW) based on NEM regional averages derived from a combination of Clean Energy Regulator (CER) post-code data for small-scale installations and random samples of individual installations[17];
- Proportion of residential (<10 kW) and commercial (>10 kW) PV systems based on a random sample of 1000 installations per region from the CER;
- Average household consumption in each NEM region based on data compiled for the Australian Energy Regulator (AER)[18];
- Residential load profiles developed from Net System Load Profile Data provided by the AEMO.[19] This data is available for each DNSP supply area. Multiple years are available (since 2002);
- Commercial load profiles based on half hourly substation demand data provided by each DNSP. The individual substations used for the commercial trace were based on those regions known to have mainly commercial and/or industrial customers;
- Number and type of distribution connected generators based on the AEMO Registration and Exemption List[20];
- Generation traces for distribution connected generators (e.g. cogeneration, large scale solar, wind etc.) based on AEMO profiles for wind and solar generation[21].

The analysis was complicated with the introduction of battery storage, in that any net generation which could have been exported can now be stored for use later on. Given the current structure of retail and network tariffs (i.e. high energy import prices, low export prices), batteries will typically be used to store energy and then used the following day to avoid purchasing energy from the grid. Annexure 2 outlines a typical profile for battery use in combination with residential PV systems under current pricing structures.

The use of batteries could change with the introduction of more cost reflective network and retail tariff structures. For example, the introduction of network credits with a strong peak demand price signal ($/kVA) could result in increased battery discharge at peak times. Chapter 5 of this report provides analysis on how battery use may change with the introduction of network credits.

Figure 3 shows the export profile by DNSP for households with PV systems. Table 8 presents the number and capacity of embedded generators (by type) in each DNSP supply area.

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

18 www.aer.gov.au/system/files/ACIL%20Allen_%20Electricity%20Benchmarks_final%20report%20v2%20-%20Revised%20March%202015.PDF

19 http://www.aemo.com.au/Electricity/Data/Metering/Load-Profiles

20 http://www.aemo.com.au/About-the-Industry/Registration/Current-Registration-and-Exemption-lists

21 Solar and Wind Traces were developed using AEMO's *National Transmission Network Development Plan* (NTNDP) datasets. Cogeneration traces were based on analysis of NEM and WEM cogeneration dispatch data.

Figure 3: Export Trace for Households with PV Systems, by NEM Region

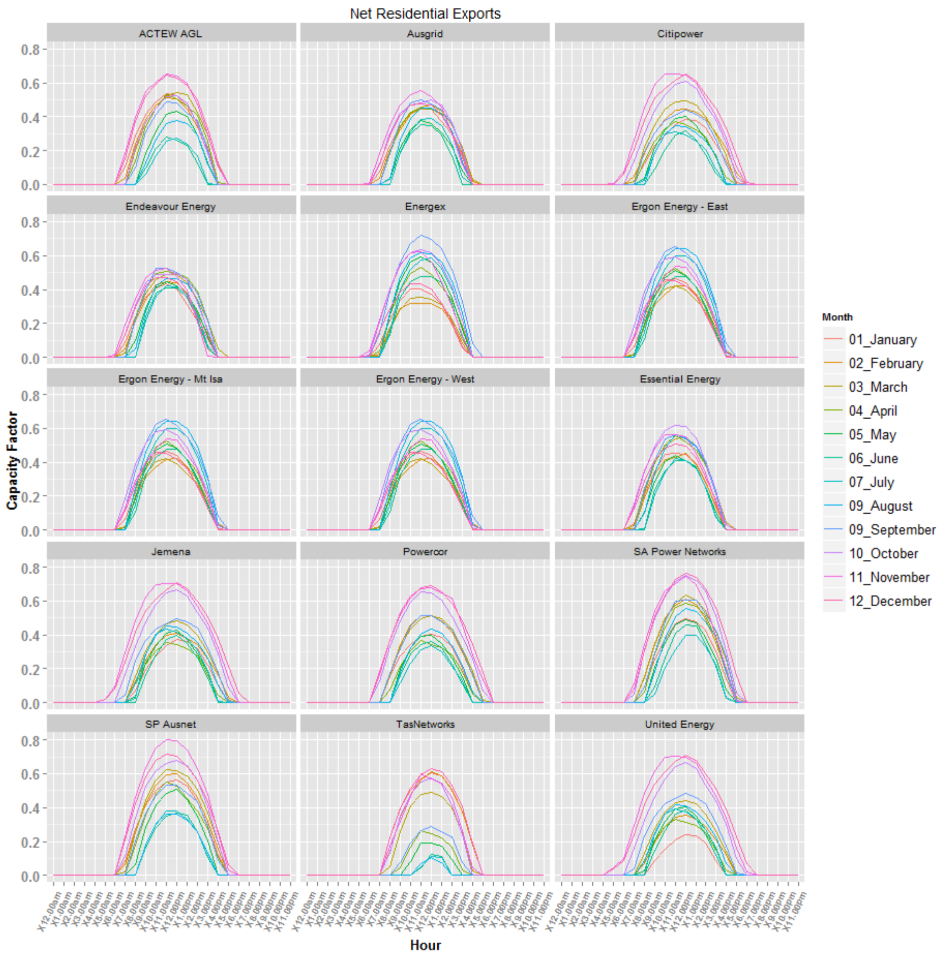


Table 8: Capacity (MW) of Embedded Generators by DNSP Supply Area (2015)

DNSP	Household Rooftop PV	Commercial PV	Distribution Solar PV	Distribution Wind	Distribution Geothermal	Cogen & Trigen	Total
ActewAGL	48.0	18.1	20	0	0	0	**86.1**
Ausgrid	198.6	75.1	1.397	0	0	29	**304.1**
Citipower	14.2	3.1	1.15	0	0	0	**18.5**
Endeavour Energy	201.4	76.1	0	1.3	0	0	**278.8**
Energex	945.3	104.4	1.95	0	0	0	**1051.7**
Ergon Energy - East	361.9	40.2	0.4	12	0	45	**459.5**
Ergon Energy - Mt Isa	5.3	0.6	0	0	0	0	**5.9**
Ergon Energy - West	24.7	2.7	0	0	0.08	0	**27.5**
Essential Energy	314.7	119.0	1	14.7	0	63	**512.4**
Jemena	39.6	8.7	0	0	0	0	**48.3**
Powercor	237.9	52.5	1.6	68.3	0	0	**360.3**
SA Power Networks	489.8	152.6	1.825	0	0	50	**694.3**
SP Ausnet	215.7	47.6	0	54	0	0	**317.3**
TasNetworks	70.8	19.3	0	0	0	101	**191.1**
United Energy	106.9	23.6	0.95	0	0	0	**131.5**
Total	**3274.8**	**743.8**	**30.3**	**150.3**	**0.1**	**288.0**	**4487.3**

3.4 LGNC payment results

The average unit prices ($/kW/annum) for the 2015-16 financial year for each DNSP and embedded generation type are summarised in Table 9 below. The average unit prices are based on dividing the Total Network Credits (see Table 10) by the total installed capacity of embedded generators (by type) in each DNSP supply area (see Table 8). A relatively low unit price (~$10/kW/annum) does not imply a low LRMC value, but could result because the coincidence of net exports with peak periods on the network are low. This is discussed further below.

Table 9: Network Credits ($) per kW of Embedded Generation, 2015-16

DNSP	Household Rooftop PV	Commercial PV	Distribution Solar PV	Distribution Wind	Distribution Geothermal	Cogen & Trigen	Average
ACTEW AGL	8.65	3.82	22.22				10.78
Ausgrid	23.02	-	11.98			21.00	17.09
Citipower	10.77	2.22	24.78				10.19
Endeavour Energy	19.77	0.16		12.89			14.38
Energex	0.63	3.04	28.53				0.92
Ergon Energy - East	18.97	1.67	33.82	26.81		40.94	19.82
Ergon Energy - Mt Isa	18.95	1.67					17.22
Ergon Energy - West	45.39	29.04			133.33		44.02
Essential Energy	17.64	-	11.51	28.34		38.46	16.40
Jemena	9.91	1.29					8.35
Powercor	13.91	5.03	26.76	15.47			12.97
SA Power Networks	11.53	3.24	11.50			25.89	10.75
SP Ausnet	10.92	-		11.53			9.38
TasNetworks	8.85	1.40				27.35	17.88
United Energy	9.48	2.53	15.92				8.28
Average	**11.21**	**1.90**	**21.45**	**16.19**	**133.33**	**31.01**	**11.17**

The above results imply the following annual payments for each embedded generator type:

- Households with PV – for a customer with a 4 kW PV system, annual credit payments will be less than $50 per annum in most DNSP supply areas.
- Commercial with PV – for a customer with a 20 kW PV system annual credit payments will be less than $60 per annum in most DNSP supply areas. In Northern Queensland (West) payments of $580 per annum could be expected.
- Distribution Solar – for a 200 kW system, payments range from $2,300 per annum in SA/Victoria, up to ~$6,700 per annum in North QLD. Payments in country NSW are around $2,300 per annum.
- Distribution Wind –for a 1 MW System, payments range from $11-15,000 in Victoria, $28,000 in country NSW and $27,000 in Northern Queensland.

- Cogeneration – for a 5 MW System, payments range from around $105,000 in NSW, $129,000 in South Australia and ~$200,000 per annum in rural NSW and Northern Queensland.

In conclusion, payments to residential and commercial customers with PV are not significant at the individual connection level since net exports are low at peak times on the network. For residential PV this is due to the fact that solar output is low at typical peak times on the network (4 to 9 PM), while the output of commercial PV systems is high when the load of these customers is high.

The total annual network credit payments by embedded generator type and DNSP are shown in Table 10 for the 2015-16 financial year. Overall, it is expected that DNSPs in the NEM would have to pay $50.14 M to embedded generators. Around 73.2% of total payments will be paid to households with PV systems.

Table 10: Network Credit Payments ($M) Using the Annual Peak Demand Method, 2015/16 Year

DNSP	Household Rooftop PV	Commercial PV	Distribution Solar PV	Distribution Wind	Distribution Geothermal	Cogen & Trigen	Total
ACTEW AGL	0.41	0.07	0.44	-	-	-	0.93
Ausgrid	4.57	-	0.02	-	-	0.61	5.20
Citipower	0.15	0.01	0.03	-	-	-	0.19
Endeavour Energy	3.98	0.01	-	0.02	-	-	4.01
Energex	0.60	0.32	0.06	-	-	-	0.97
Ergon Energy - East	6.86	0.07	0.01	0.32	-	1.84	9.11
Ergon Energy - Mt Isa	0.10	0.00	-	-	-	-	0.10
Ergon Energy - West	1.12	0.08	-	-	0.01	-	1.21
Essential Energy	5.55	-	0.01	0.42	-	2.42	8.40
Jemena	0.39	0.01	-	-	-	-	0.40
Powercor	3.31	0.26	0.04	1.06	-	-	4.67
SA Power Networks	5.65	0.50	0.02	-	-	1.29	7.46
SP Ausnet	2.36	-	-	0.62	-	-	2.98
TasNetworks	0.63	0.03	-	-	-	2.76	3.42
United Energy	1.01	0.06	0.02	-	-	-	1.09
Total	36.70	1.41	0.65	2.43	0.01	8.93	50.14

Some observations from the results include the following:

- Payments by Ergon Energy – East ($9.11 M), Essential Energy ($8.4 M) and SA Power Networks ($7.5 M) are significantly higher than in most other DNSP supply areas. This is due to a higher penetration of household PV systems than in most other supply areas;
- Payments are also notable for TasNetworks ($3.42 M), Endeavour Energy ($4.01 M), SP Ausnet ($2.98 M), Powercor ($4.67 M) and Ausgrid ($5.2 M). The reasons for this include the following:
  - Estimated payments to cogeneration facilities in TasNetworks ($2.76 M)
  - Estimated payments to residential PV in SP Ausnet, Powercor, Ausgrid and Endeavour Energy supply areas.
  - Residential payment to Powercor are notably higher than for other DNSP’s in Victoria due to a higher penetration of residential PV and higher LRMC for distribution upgrades.

- It was expected that payments in South East QLD (Energex) and North Queensland (Ergon Energy-West) would also be high due to the high penetration of PV's in those regions. However, the peak period in QLD is between 3-4 PM and 8-9 PM, which implies that solar PV output is low (or zero) at those times after 5 PM.
- Payments are relatively low by Actew AGL, CitiPower, United Energy and Jemena due to the following factors:
  - Lower penetration of household PV in those supply areas;
  - Lower solar contribution for PV in those supply areas – less exports;

Notable payments (as a % of the total) to other embedded generator types included the following: Cogen/Trigen (17.8%), Distribution Connected Windfarms (4.9%) and Commercial PV (2.8%).

4. LGNC Pricing In Practice

4.1 Designing a LGNC Price Structure

Having determined the annual potential benefits of embedded generation, we can determine network credit prices that could be applied in practice and are consistent with the pricing practices of DNSP's. Network credit prices could be based on energy prices (c/kWh), demand charges ($/kW/day) or some combination of both.

Demand tariffs for commercial and industrial customers have been widely applied by both retailers and DNSP's on the basis that these customers can implement practices to reduce peak demand. For example, implementation of energy efficient lighting in commercial buildings, or installing power factor equipment to better manage kVA demand.

Demand tariffs have not been widely applied to households or small business customers (low voltage). However, most DNSP's have proposed transitioning to demand charges for all low voltage customers in their Tariff Structure Statements covering the period 2016 to 2021.

The only DNSP's that have not proposed demand charges for households and small business customers are the three DNSP's operating in NSW: Endeavour Energy, Essential Energy and Ausgrid; although Ausgrid is proposing a demand charge for small business customers.

The merits of basing network credits on time of use energy or demand tariffs will depend critically on whether embedded generators can respond to these pricing signals.

Most renewable generation (e.g. solar PV, wind etc.) will typically only operate when the renewable resource is available. Even in the case of cogeneration or trigeneration, the operation of the generator is usually dictated by the need to provide a third energy stream (e.g. steam). In the case of cogeneration facilities, they are semi dispatchable in that generators can operate in conventional generator mode (i.e. non-cogen mode).

In the case of solar and wind generators, once installed the profile of production does not vary except as a function of weather related factors (e.g. solar radiation levels, cloud cover etc.). However, the design and placement of the generator can change the production profile of the generator. For example, by placing PV systems on the western side of buildings, these systems can increase output in the late afternoon which may better coincide with the peak demand of network systems. Equally, locating a wind farm to ensure that it produces more output during the day, rather than overnight, will also provide more value to network providers.

Appropriate structured network credit prices could provide incentives for customers to increase the size of the PV system that they install in order to increase net exports (after internal customer load is met). For some networks, the output of PV systems and network peaks may not coincide, with the result that these systems are receiving payments in excess of the value that they provide to DNSPs. However, the introduction of time of use pricing for network credits could provide incentives for customers to install a battery in combination with a PV system so that they can recharge the battery at non-peak times (morning period) and discharge the battery at peak times on the network (in the afternoon).

Network credits based on time of use energy and demand charges can provide incentives for customers to reduce load at peak times in order to maximise net exports at peak times on the network – analogous to demand tariffs providing incentives for business customers to reduce load at peak times. There is precedent for customers reducing demand in response to price signals. Many residential customers who had access to generous feed-in tariff rates (40 to 50 c/kWh) that were offered by State Governments in all jurisdictions, resulted in customers minimising customer load in order to maximise net exports. This could also occur with the introduction of network credits.

There is sufficient prima facie evidence to suggest that the design, placement, sizing and net exports of embedded generators could be influenced by the price structure of network credits. For the purposes of this study, we have designed a potential pricing structure that could be applied by DNSP's in practice. This method is referred to as the Monthly Peak Credit Method.

Under this method, we calculate peak energy or peak demand credits (whichever is applicable) and apply on either a monthly or seasonal basis. Peak demand periods are consistent with network pricing parameters outlined by DNSP's in their Tariff Structure Statements. Under this method, there are no credits provided in shoulder or off peak periods.

The Monthly Peak Credit Method replicates how DNSPs are more likely to price credits to embedded generators and is consistent with typical billing cycles. LGNC price structures are based on either peak energy prices (c/kWh) or monthly peak demand charges ($/kW/day). In this case, peak demand periods are based on published network pricing structures, which may be longer than the 'true' peak periods for a DNSP. This dilutes the price signal to embedded generators to export at peak times compared to the Annual Peak Demand Credit Approach. However, while not reflecting economic signals as accurately as the Annual Peak Demand Credit Approach, it is more closely aligned with DNSP charging practices.

4.2 Calculation of Network Credits using the Monthly Peak Credit Method

Under this method, we calculate peak energy or peak demand credits (whichever is applicable) and apply on a monthly basis. Peak demand periods are consistent with the network pricing parameters outlined in the Tariff Structure Statements of DNSPs outlined in Chapter 3.2.1

In most cases, monthly demand charges apply to all customer classes and voltage levels. However, in the case of NSW distributors that have not proposed demand tariffs for residential or small business, we have developed a peak time of use energy tariff. The applicable network credits (or prices) based on the Monthly Peak Credit Method are shown in Annexure 4.

The overall annual payments made by DNSP's and embedded generator type under this pricing methodology (by design) are the same as the total payment amounts provided in Table 9 using the Annual Peak Demand Method for determining network credit value.

5. Limitations of the Modelling Approach

The previous modelling results are reliant on a number of simplifying assumptions which can impact the accuracy of the results.

5.1.1 Results are Not Dynamic

The modelling undertaken excluded any potential responsiveness of embedded generators associated with the introduction of network credits. This is despite peak demand pricing ($/kVA) providing a signal for customers and embedded generators to increase net exports at peak times. For example, customers could reduce electricity consumption during peak demand times in order to increase net exports from their PV systems. Alternatively, a customer could store electricity (i.e. battery storage) for use at peak times in order to increase net exports as highlighted in Chapter 6.

This limitation suggests that future work should be undertaken to consider how generators and also customers would potentially respond to various network credit pricing structures.

5.1.2 Peak Demands on Networks May Not Coincide

Power flow patterns across networks can occur as follows:

- Radial feeders from zone substations which have power flows reflecting the customers taking power on each feeder;
- Power flows to zone substations (sometimes referred to as sub-transmission) reflecting the power flows of all the feeders off that zone substation (i.e. residential, commercial, and semi-rural customers);
- Power flows on the transmission network reflecting the power flows to the sub-transmission systems, the location of major generation, and the configuration of transmission lines.

Each of these elements of the network could have maximum power flows at different times. Thus the impact of local generation, and the corresponding value of LGNCs, may differ significantly across various network elements.

Without undertaking a complete review of the coincidence of peak demand on distribution and transmission networks, assumptions have had to be made on the coincidence of maximum power flows and how local generation exports would impact those flows (and thus the capacity needed at the various locations in the network).

For our analysis, we have assumed coincidence of the peak demand for both transmission and various distribution assets (e.g. LV, HV and sub-transmission). While peak demands are highly correlated, they are not perfectly correlated as our analysis suggests. As a result, our analysis may tend to over-state the value of embedded generation.

5.1.3 Embedded Generation May Drive Network Investment

As highlighted in Chapter 2.1, investment in embedded generation may result in the need for investment in network capacity in regions with a high penetration of embedded generation. As highlighted earlier, in some regions, PV penetration rates of 64-65% have been achieved in South Australia and Queensland. As a result, net exports of PV could drive the need for augmentation of the network (e.g. management of reverse power flows).

Providing network credits to customers in these regions could further stimulate investment in embedded generation and result in rising costs.

5.1.4 Proposed Structure of Network Credits Requires Interval Capable Meters be Installed

Our analysis has assumed that residential and small business customers will be faced with network credits based on either demand ($/kVA) or time of use energy charges. This will require that customers with embedded generation have either interval capable or smart meters installed. This imposes additional costs on providers of metering services since they will be required to either install interval capable meters or re-programme existing meters.

Smart meters have already been rolled out in Victoria which are capable of measuring PV exports on an interval basis. However, there has not been a mandatory roll out of smart meters in other jurisdictions.

The costs of upgrading import/export meters to permit the application of peak demand and time of use energy network credits has not been incorporated into this analysis.

6. Payback on PV and Battery Storage Analysis

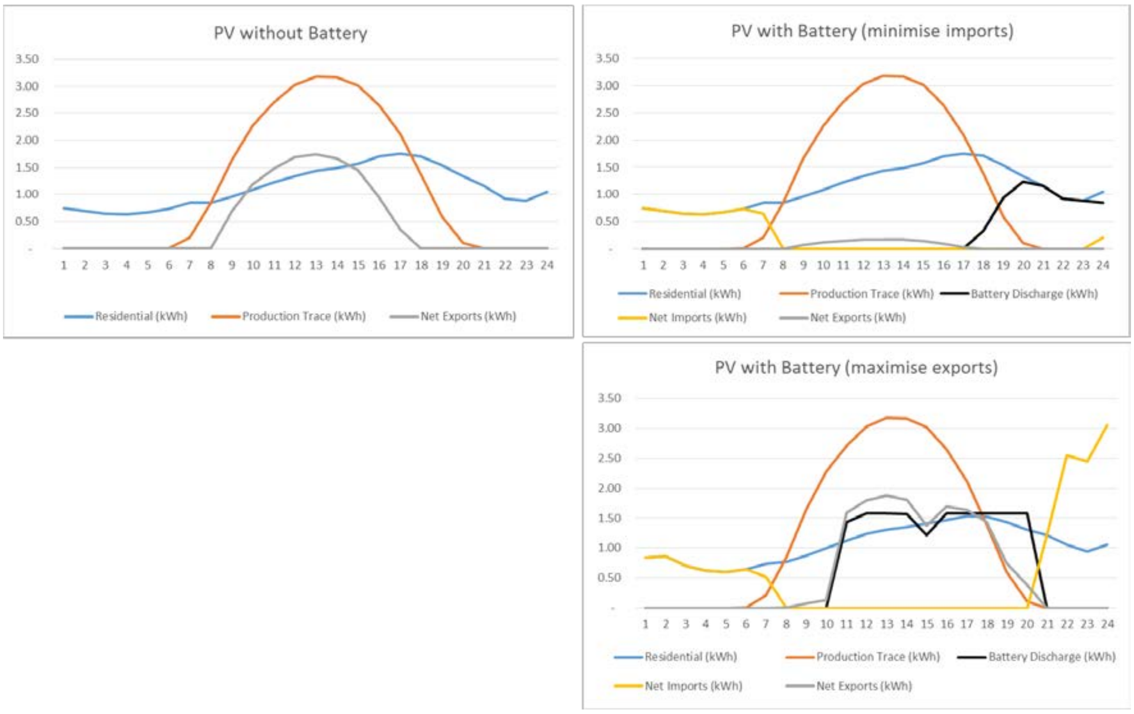
By design, the introduction of a network credit will increase the payback for customers wanting to invest in embedded generation and battery storage. In order to estimate how important the credit will be in promoting these technologies, Marsden Jacob undertook analysis to determine the payback on these technologies in each DNSP supply region for a residential household. For this analysis, we have assumed that the customer installed a 4 kW PV system and a 7 kWh battery (where applicable). Marsden Jacob has estimated retail tariff prices (based on flat rate tariffs inclusive of GST) for each state. In this analysis, it is assumed that customers can access off peak energy at 8 c/kWh to charge the battery from the grid if required. Retail Solar buyback rates are set at 8.8 c/kWh (includes GST).

The payback was determined for the following scenarios:

- Customer installs a PV system only;
- Customer installs a PV and battery storage system. In this case, the customer only wants to minimise electricity imports from the grid (conventional approach given high unit electricity prices).
- Customer installs a PV and battery storage system. In this case the customer wants to maximise the output of the PV system at peak times in order to benefit from the network credit.

Customer demand (blue), the PV production trace (blue) and net exports from PV (grey) are shown for each scenario in the Powercor supply area (Victoria). Net imports (yellow) are shown in the battery storage cases.

Figure 4: Net Exports with and without Battery Storage, Peak Summer Period – Powercor



For this analysis, the peak period for calculating the network credit to residential households is based on the peak periods outlined in Table 6 for each DNSP (which may not be the same as DNSP peak pricing periods).

In the PV without Battery Scenario for Powercor, the average net demand exported over the peak period is 0.29 kW. If a battery is introduced and the customer attempts to minimise purchases of grid energy (avoid paying 25 c/kWh), then net exports fall close to zero, with the PV system charging the battery during the day and discharging from the battery in the evening. With this operation of the battery, the customer will not benefit from the introduction of the network credit.

In the PV with battery case whereby the customer attempts to maximise exports to benefit from the network credit, the customer uses cheap off peak energy to partially charge the battery overnight and uses the PV system to top up the battery in the morning. The total capacity of the battery is then dispatched during peak times to meet the customer's load, which permits the PV system to export on average 0.98 kW over the peak period; a significant increase in average export capacity (240% increase in average capacity).

The annual network credit amount is $39 per annum for the PV without battery case and $130 per annum for the PV with battery (maximise exports) case, and zero for the PV with battery (minimise imports) case. The improvement in financial and simple paybacks[22] resulting from the introduction of the LGNC is shown in Table 12 for a residential PV customer in the Powercor supply area. The financial payback in the PV without battery case improves by 4.2 months (0.35 years). The financial payback on the PV with battery (maximise exports) case improves by 23 months (1.92 years), although given that the financial payback without the LGNC is 16.4 years, this still does not make battery storage economic at current prices ($1300 per kWh).

Table 11: Improvement in Paybacks for PV Systems with Network Credits – Powercor

Powercor			
Paybacks on Investment (Years)	PV	PV and Battery Avoid Imports	PV and Battery Maximise Outputs
Financial Payback - No LGNC	8.46	16.94	16.42
Simple Payback - No LGNC	6.64	10.86	10.65
Financial Payback - With LGNC	8.10	16.89	14.50
Simple Payback - With LGNC	6.42	10.84	9.84
Financial Payback Improvement with LGNC	0.35	0.05	1.92
Simple Payback Improvement with LGNC	0.22	0.02	0.82

The payback on investment for battery storage will improve with the introduction of time of use energy and demand charges. However, it will take considerable reductions in battery storage costs to bring down paybacks to levels that will encourage customers to invest in this technology in NEM regions. Even a halving of battery costs ($650 per kWh) would still result in financial paybacks on investment of around 9-10 years at current retail electricity and feed-in tariff rates.

Analysis of other DNSP regions indicates (summarised in Table 13 below) that the introduction of network credits will improve the payback on PV only and PV and battery storage combinations in NSW, QLD and SA. In the case of Ergon Energy East, the payback on a PV and battery storage combination is improved by almost 3.5 years (financial payback). Payback improvements on PV only systems is very modest in most states; considerably less than 1 year in most jurisdictions.

This suggests that the introduction of LGNCs will only provide a modest incentive for the increased take-up of PV only systems by residential households. However, LGNC's will provide a more significant incentive for customers to install PV and battery storage systems, especially as battery storage costs decrease overtime.

22 Takes into account the time value of money to calculate a payback period, whereas simple paybacks are only concerned with nominal dollars.

Table 12: Paybacks on PV and Battery Storage, Selected DNSP supply areas

Ergon Energy - East			
Paybacks on Investment (Years)	PV	PV and Battery Avoid Imports	PV and Battery Maximise Outputs
Financial Payback - No LGNC	7.21	13.53	13.06
Simple Payback - No LGNC	5.84	9.39	9.17
Financial Payback - With LGNC	6.55	13.33	9.59
Simple Payback - With LGNC	5.39	9.30	7.32
Financial Payback Improvement with LGNC	0.66	0.20	3.47
Simple Payback Improvement with LGNC	0.45	0.09	1.85

SA Power Networks			
Paybacks on Investment (Years)	PV	PV and Battery Avoid Imports	PV and Battery Maximise Outputs
Financial Payback - No LGNC	5.53	9.38	8.97
Simple Payback - No LGNC	4.68	7.20	6.96
Financial Payback - With LGNC	5.49	9.38	8.51
Simple Payback - With LGNC	4.65	7.20	6.67
Financial Payback Improvement with LGNC	0.05	0.00	0.46
Simple Payback Improvement with LGNC	0.03	0.00	0.29

Endeavour Energy			
Paybacks on Investment (Years)	PV	PV and Battery Avoid Imports	PV and Battery Maximise Outputs
Financial Payback - No LGNC	7.89	15.54	15.04
Simple Payback - No LGNC	6.29	10.29	10.08
Financial Payback - With LGNC	7.11	15.41	12.91
Simple Payback - With LGNC	5.78	10.24	9.10
Financial Payback Improvement with LGNC	0.79	0.13	2.13
Simple Payback Improvement with LGNC	0.51	0.05	0.98

In addition, the introduction of the network credit could also provide incentives for the over sizing of the PV systems by households. However, our analysis suggests that this incentive is modest. By upgrading the PV capacity to 5 kW (instead of 4 kW), the financial payback for PV is improved by a further 2 months (in the Powercor supply region).

In conclusion, LGNC's provide only a modest incentive for the increased uptake of PV only systems, and are unlikely to result in a significant uptake of PV and battery storage combinations until there is a significant reduction in battery storage capital costs.

Annexure 1: AEMC Scope of Work

The AEMC has requested that Marsden Jacob use publicly available data and information to produce estimates of the following:

- The value of a unit of LGNC (in kWh) that would be paid out to owners of embedded generators by each distribution network service provider (DNSP) in the National Electricity Market. To estimate the value of a unit of LGNC, the consultant is expected to make use of published long-run marginal cost (LRMC) figures used to inform each DNSPs consumption tariffs in its proposed tariff structure statement. The calculation of the value of LGNCs should mirror each DNSPs cost-reflective consumption tariffs (e.g. time-of-use), as published in each DNSPs tariff structure statement. Additionally, if a DNSP has different consumption charges for different locations on its network, the consultant should calculate separate LGNC values for each such location.
- The cumulative value of LGNCs paid in a 12-month period by each DNSP in the National Electricity Market to one typical (or representative) embedded generator of each of the following types:
  - Household rooftop solar PV without battery storage
  - Household rooftop solar PV with battery storage
  - Commercial property solar PV
  - Distribution-connected solar PV farm
  - Distribution-connected wind farm
  - Distribution-connected geothermal plant
  - Cogeneration or trigeneration facility.
- To estimate the cumulative value of LGNCs paid to each type of embedded generator, the consultant should use an estimate of typical energy exported from each of the above types of generator in a typical 12-month period, based on publicly available information.
- The total value of all LGNCs paid in a 12-month period by each DNSP in the National Electricity Market to all embedded generators in its distribution area. To estimate the total value of LGNCs paid by each DNSP, the consultant should use an estimate of the number of embedded generators connected to each distribution network, based on publicly available information.

Annexure 2: Study Methodology and Data Sources

A2.1 Embedded Generation Types

A2.1.1 Rooftop PV

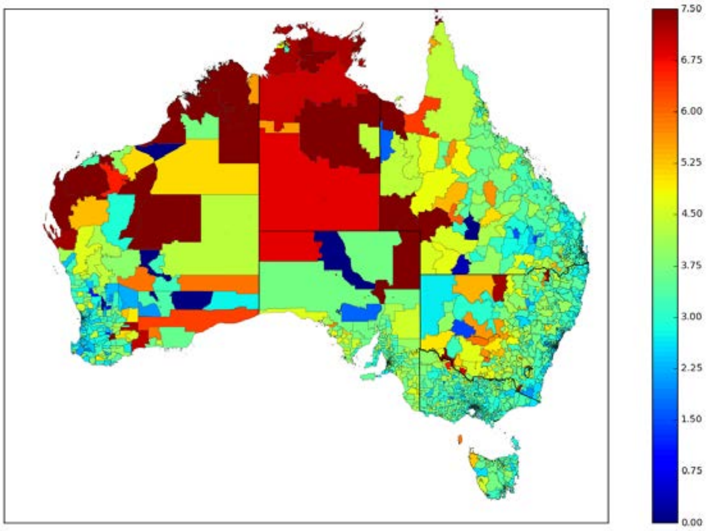
The total amount of rooftop PV installed in the NEM was sourced from the Clean Energy Regulator[23] (CER) which tracks the installation of all PV installations that qualify for the Commonwealth Government's Small-scale Renewable Energy Scheme.

(i) Residential PV

To quantify the amount of rooftop PV installed in each DNSP, a list of postcodes for each DNSP was compiled. This list was then used to map rooftop PV installation up to December 2015 sourced from the CER to their respective DNSP supply areas. The list was then aggregated to produce a total installed capacity (MW) of embedded generation type for each DNSP supply area.

Figure 5 below shows the average installation size of rooftop PV by postcode up to a maximum of 7.5kW.

Figure 5: Average Rooftop PV Installation by Postcode up to 7.5 kW



Source: Postcode Data provided by Clean Energy Regulator

Most PV installations were located in city regions, although these tended to be of a smaller size then those in regional areas.

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

(2) Residential PV with battery storage

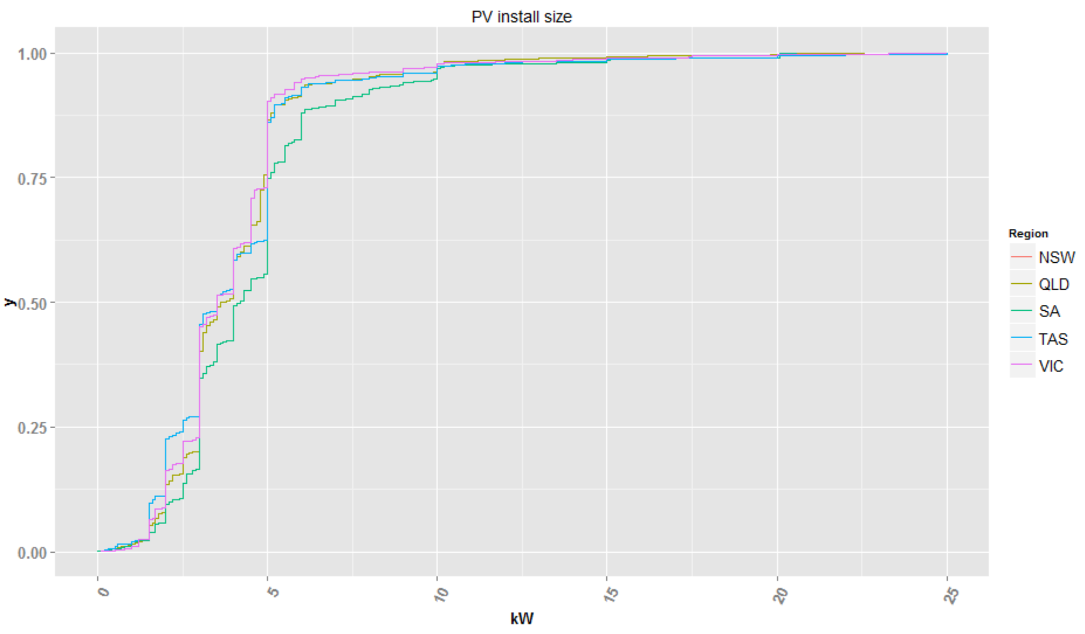
The installation of battery storage in combination with rooftop PV systems is only in the early adopter stage of development. Unlike PV panels which are eligible for Small-scale Technology Certificates (STCs), batteries are not tracked by a central body making it difficult to estimate the number and size of installations across the NEM.

However, in this study, we shall determine what the likely value of exports from a household with PV and battery storage combination in order to understand whether customers will be incentivised by LGNC's to invest in these technologies.

A2.1.2 Commercial PV

Data provided by the CER reports on the total number of solar PV installations in a postcode area and total capacity of these systems (kW). The data does not distinguish between commercial and residential systems. For this study, we have assumed that any PV installation exceeding 10 kW is co-located with a commercial load.

Figure 6 Cumulative plot of PV Installs by Size



On this basis, commercial PV accounted for 3 to 8 % of all installations in each region. When aggregating the capacity of these installations in each NEM region, it represented between 10% - 27% of total capacity.

A2.1.3 Distribution Wind & Solar

The amount of installed distribution connected wind and PV generators were based on multiple data sources. The primary source was the AEMO Registration and Exemption List[24] for March 2016 which provides a comprehensive list of both Market and Non-Market Generators. Smaller

[24] http://www.aemo.com.au/About-the-Industry/Registration/Current-Registration-and-Exemption-lists

wind generators were not listed, which were mostly constructed before the introduction of a national LRET target.

A database of distributed PV generators that exceed the 100kV maximum for commercial systems was constructed and was summed by DNSP to provide the installed capacity for Solar PV. Most distribution PV projects were in a range of between 200 – 3000 kW.

A2.1.4 Geothermal

There is only one distribution connected geothermal energy project in the NEM (Mt Isa) capable of exporting energy.

A2.1.5 Trigen/Cogen

As with wind and solar, the primary source of information on Trigen and Cogen systems was the AEMO Registration and Exemption List[25] March 2016. Small backup generators (typically diesel) are usually less than 5 MW in size and were not modelled as part of this study.

A2.2 Embedded Generation Traces

An average generation profile was constructed for each embedded generator type by DNSP. All profiles consisted of the following:

- Scaled hourly generation. Scaled generation was used as installed capacities can be updated independently for projected future years.
- Weekday & Weekend profiles. Base generation for wind and solar share a profile for both weekdays and weekends as these are intermittent generators and are not influenced by peak period definitions.
- Monthly energy values are used as these align with the DNSP base tariff structures.

A2.2.1 Solar PV Traces

There are four PV configurations that need to be modelled for this study:

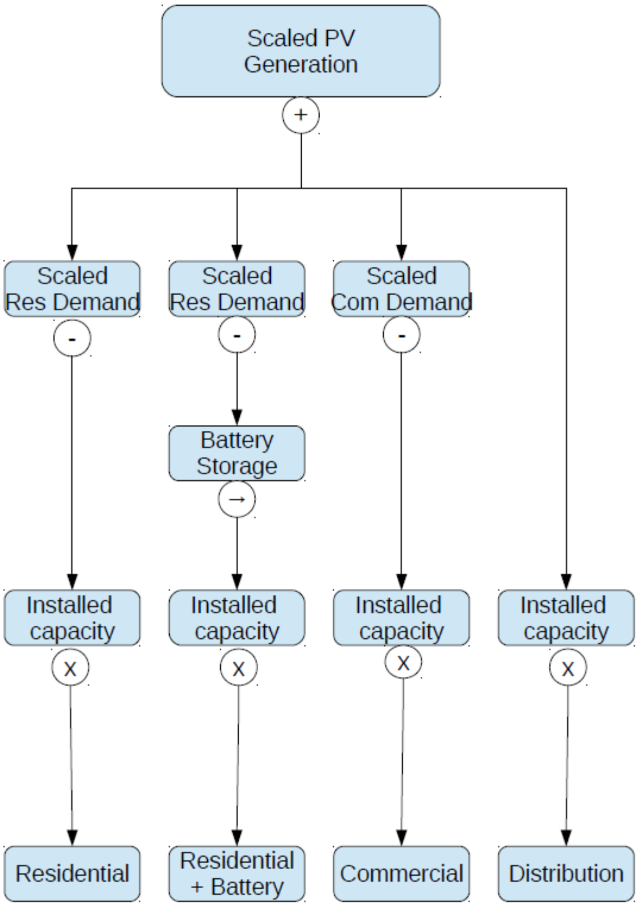
- Residential PV;
- Residential PV with battery storage;
- Commercial PV; and
- Distribution connected Solar PV.

The common factor to all these installations is the use of photovoltaics cell for base generation. Only a small fraction of installed solar were concentrated solar PV/thermal, which did not have energy storage, implying that these systems will have the same generation trace as PV systems.

The main differences between net generation traces results from the amount on on-site electricity use. Figure 7 below provides an outline of the process used to build each of the net solar generation traces.

25 http://www.aemo.com.au/About-the-Industry/Registration/Current-Registration-and-Exemption-lists

Figure 7: Solar Trace Development Chart



A2.2.2 Scaled PV Generation Trace

The scaled generation trace for solar PV was based upon the capacity factor traces used by AEMO as part of the 2015 National Transmission Network Development Plan (NTNDP). The traces were used to provide scaled hourly generation by zone. The NTNDP provides a break down into various NEM regions as shown below.

Figure 8: NTNDP Zone Map for NSW and Victoria

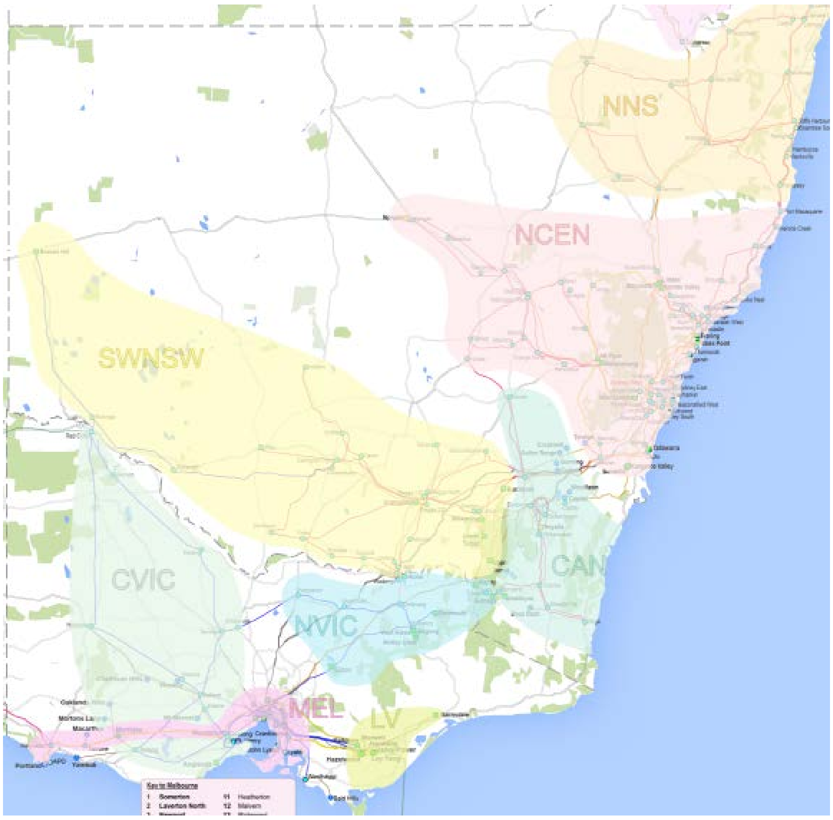
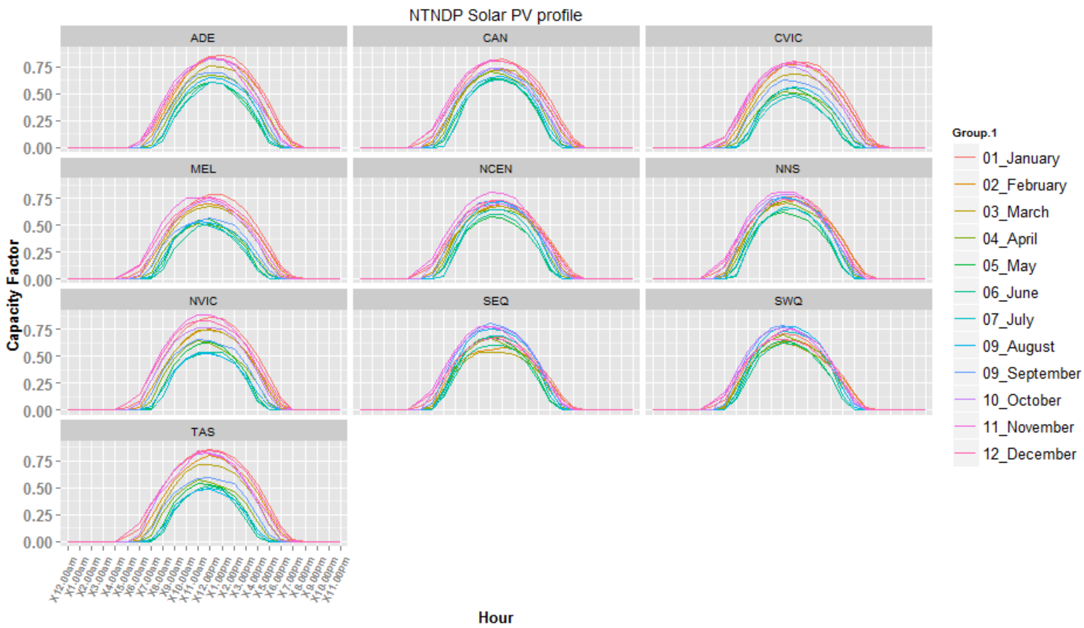


Figure 9 shows the average generation profiles used for each of NTNDP zones used in the model. The maximum capacity factor during summer was 80-85% of installed capacity as overcast and cloudy conditions result in lower outputs.

Figure 9: Expected PV Generation Profiles by NTNDP Zone



A2.2.2 Net Residential Export Traces

The net residential export traces for households with PV systems were produced by deducting a standard residential load profile (for each NEM region) from the PV generation trace. This process was repeated for each DNSP on a monthly basis.

(1) Net Exports Without battery

To provide an estimate of the amount of energy exported to the grid, a typical residential profile of demand and PV was constructed for each region. Residential demand was weighted between peak and off peak periods. The average residential system size was estimated using a sample of 1000 installations for each region with a capacity less than 10kW.

Table 14 below shows the assumed size of a typical household with PV in each NEM region. The average residential consumption (kWh) is based on electricity consumption data for 2011 when PV penetration was relatively low[26]. This is an approximate estimate of the total electricity requirements for a household, regardless of whether the energy is provided by rooftop PV or is grid supplied. As shown below, there are significant differences in the annual consumption due to both weather related factors and the penetration of natural gas (especially used for winter heating in Victoria).

Table 13: Residential PV System Size by NEM Region

	Units	ACT	NSW	QLD	SA	TAS	VIC
PV system size (a)	kW	3.72	3.72	4.07	4.13	3.68	3.67
Annual Residential Consumption	kWh	8026	6730	6791	5967	9404	5432
Average Daily Consumption	kWh	21.98	18.44	18.61	16.35	25.76	14.88

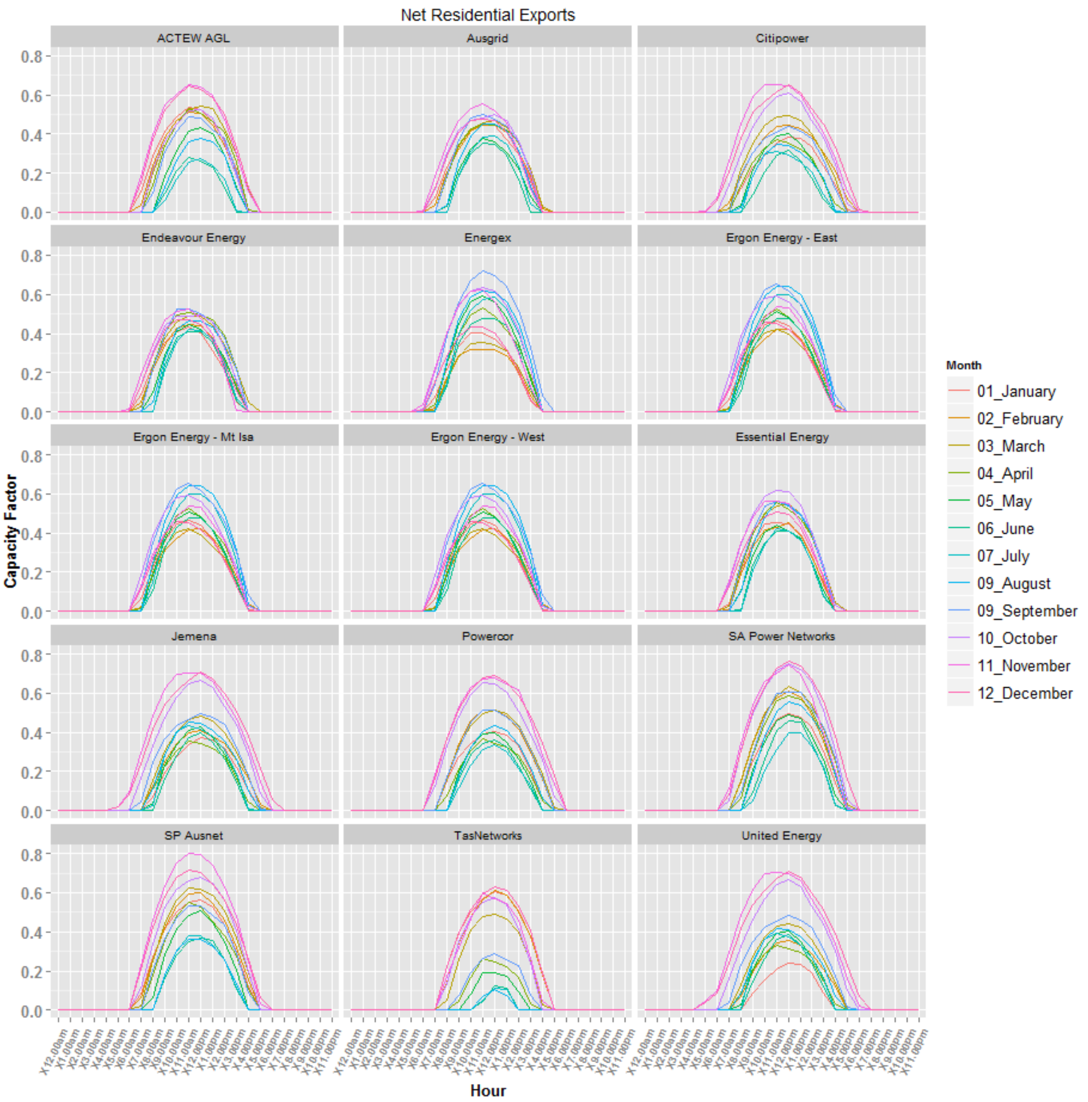
Notes:

(a) PV System Size refers to panel capacity and not inverter size, since the inverter is likely to be oversized to allow for additional panels to be installed.

26 www.aer.gov.au/system/files/ACIL%20Allen_%20Electricity%20Benchmarks_final%20report%20v2%20-%20Revised%20March%202015.PDF

The monthly net residential PV traces for each DNSP supply area are shown below by month.

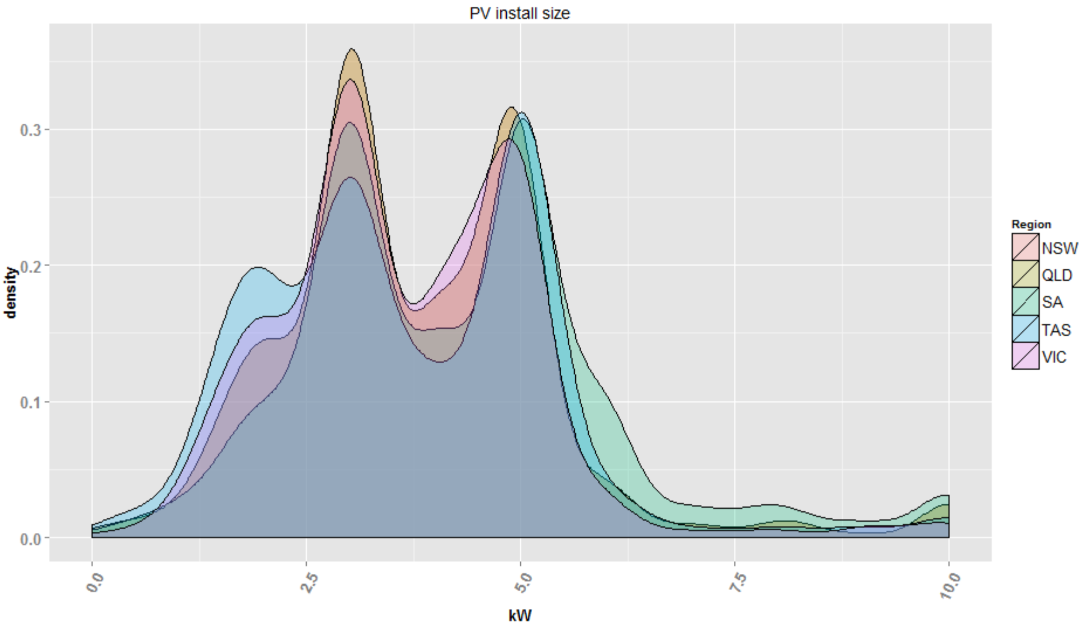
Figure 10: Residential Net Exports PV Profiles



Source: Marsden Jacob

The distribution of installed capacity for residential PV systems is shown below for each state in the NEM. Clearly, the distribution is bimodal, with most households either installing 3 or 5 kW systems.

Figure 11: Distribution of Residential Solar PV by Panel Capacity (kW)



(2) Net Residential PV Exports With Battery Storage

For residential households with PV and battery storage the trace was modified to have excess generation stored rather than exported to the grid. This resulted in a trace with much less electricity exported to the grid during the winter period, and more exports in late afternoon during summer (i.e. battery is fully charged and electricity has to be exported).

Figure 12 below shows the change in net demand of a residential household with PV & Battery installed (refer System setup 1).

Figure 12: Residential Demand and Net Exports with PV and Battery Storage

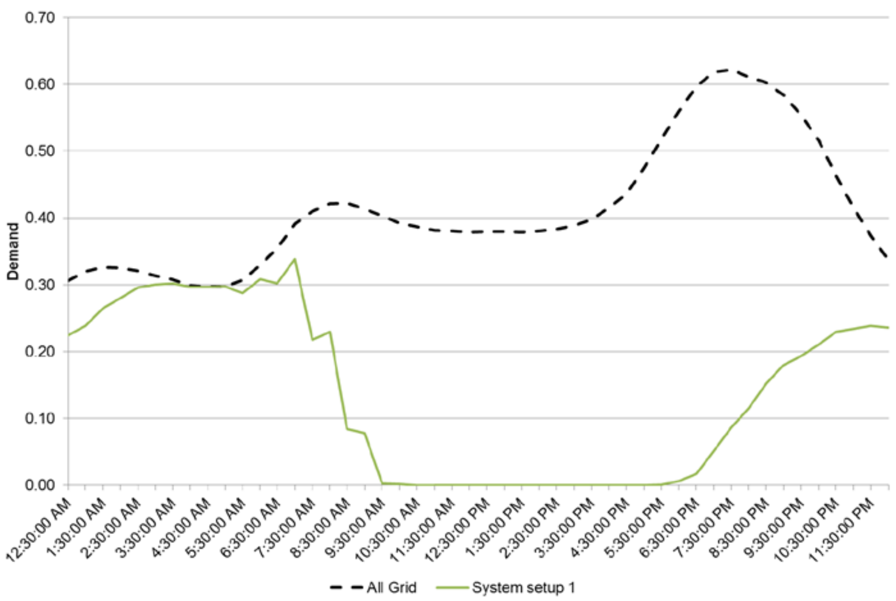
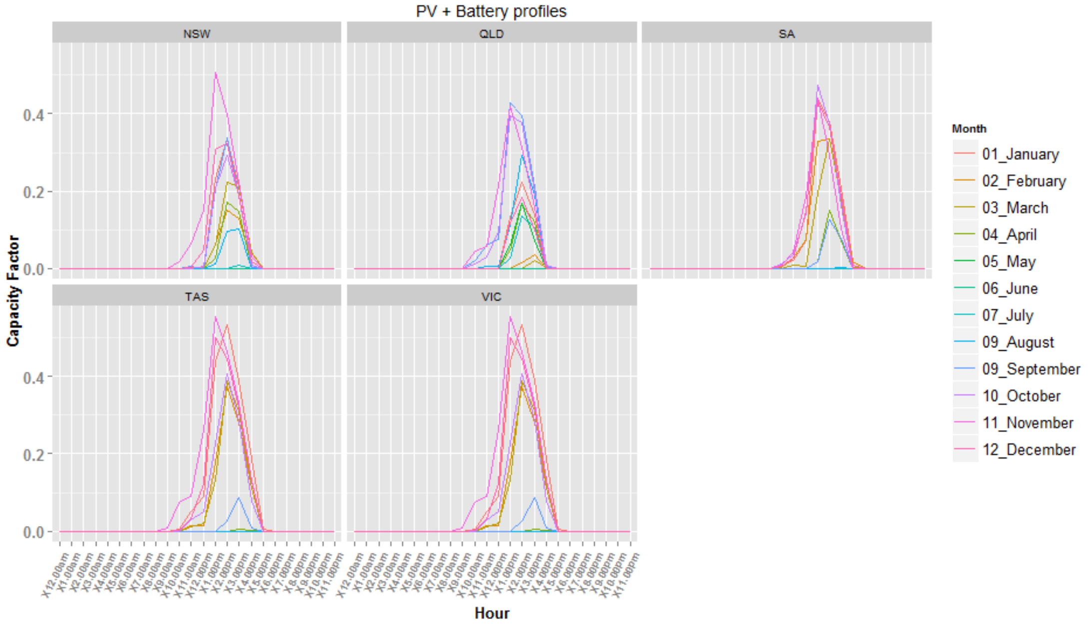


Figure 13 below shows the energy exported to the network by NEM state. Even during summer, the exported capacity is less than 50% of installed PV capacity.

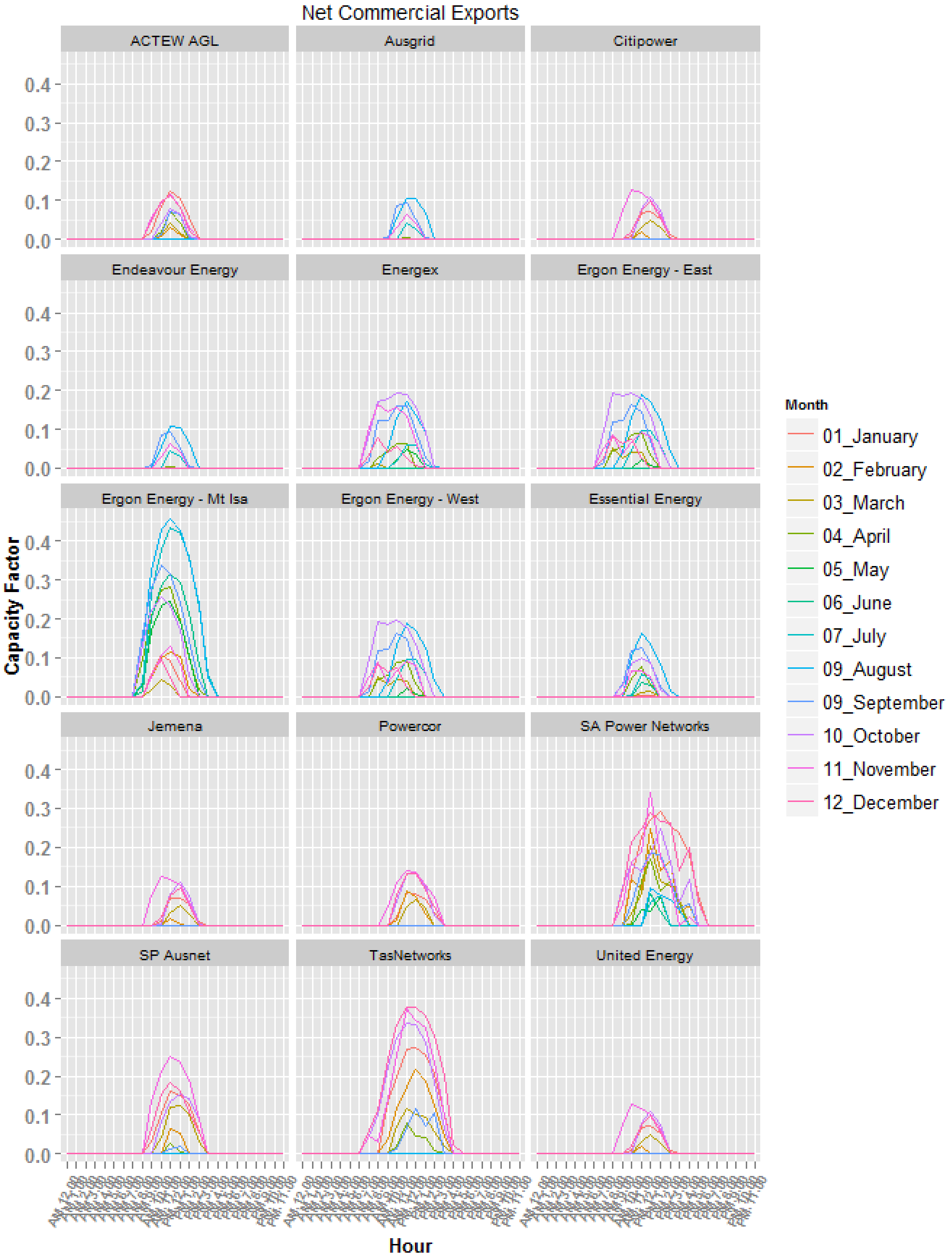
Figure 13: PV with Battery Profiles by Region



A2.2.3 Net Commercial Export Traces

The net commercial export trace was produced using the same method as the net residential export trace. As commercial load profiles have high demands at the same time that PV systems are generating (mid-morning to late afternoon), net export to the grid is much less than for a similar sized residential system. In addition, Commercial PV installations were also assumed to be 'right' sized given that there is typically less variation in commercial loads across the week, month and season, when compared to residential customers. Net commercial export traces are shown below.

Figure 14: Net Commercial Export Traces



A2.2.4 Distribution Connected Solar

For distribution connected solar it was assumed that all generation would be exported to the grid and the full scaled generation trace was used.

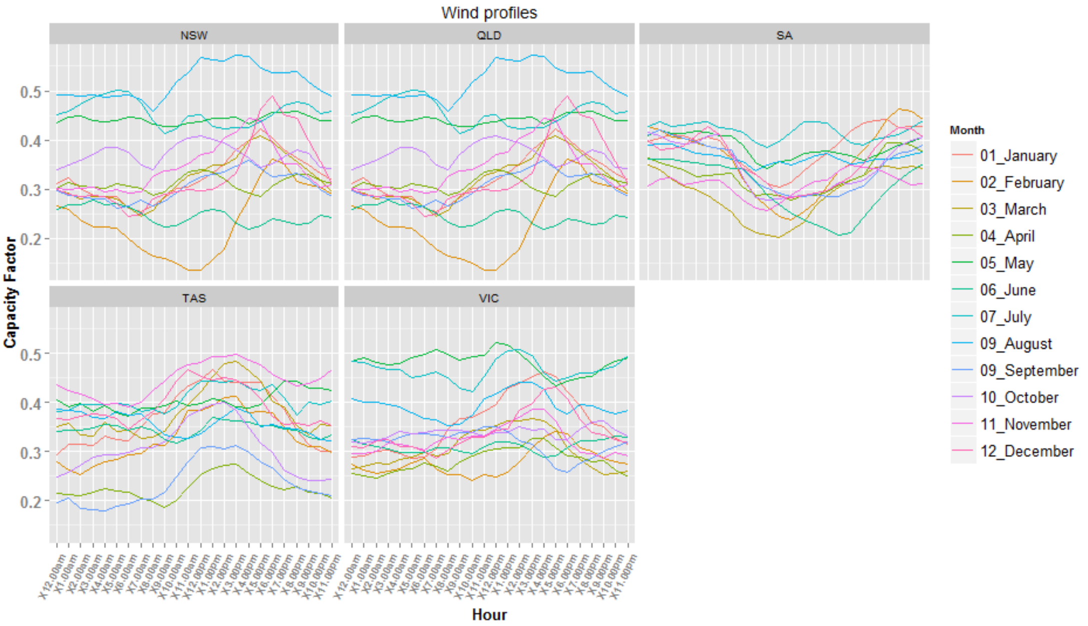
A2.3 Wind

Wind generation was assumed to be all distribution connected and that all electricity produced was exported to the grid. Small-scaled wind, although covered by the SRES, was not included in total installations listed by the CER in 2015.

Marsden Jacob has estimated that Australia wide wind farms contributed to 341 STCs - equivalent to 12.5kW or 3-4 households with PV systems.

The wind trace used was based upon the monthly average wind generation in 2015 for existing semi scheduled wind generators. As Queensland has no existing semi-scheduled wind generation, the NSW trace was used instead. The hourly profile for wind is displayed in Figure 15 below

Figure 15: Wind Generation by NEM Region



There was a slight bias towards more electricity generated in winter months for all regions.

A2.4 Geothermal & Cogen/Trigen

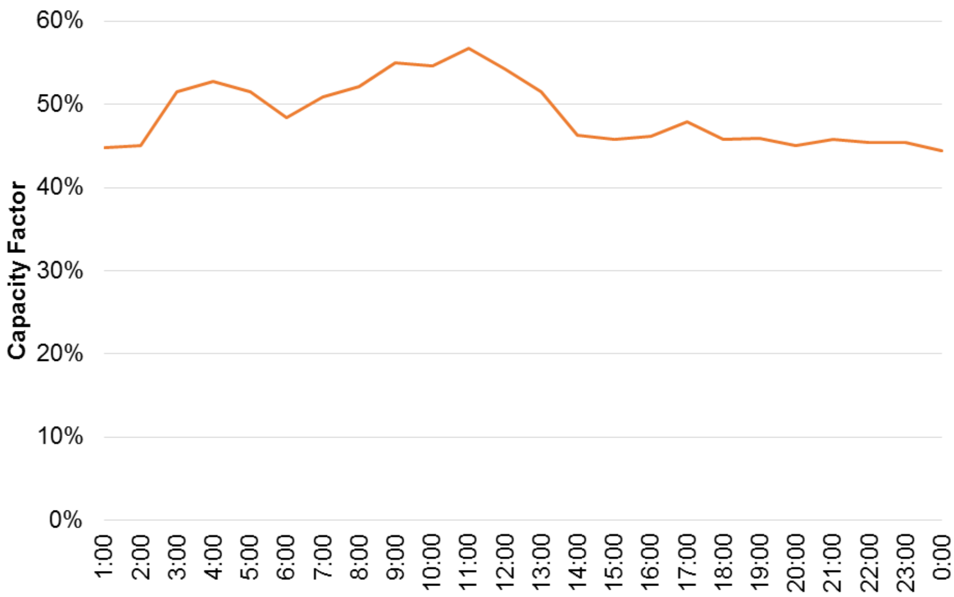
A2.4.1 Geothermal

Geothermal was assumed to operate at a relatively flat capacity factor of 85%. Only 80kW of Geothermal is currently installed in Queensland. A flat capacity was assumed as geothermal is a renewable baseload source unlike solar and wind which are intermittent.

A2.4.2 Cogen/Trigen

Cogeneration output was based on an analysis of the historic generation profile of larger scheduled cogeneration plant during 2015 & 2016 from both the NEM and WEM. The analysis was used to produce an expected generation profile. As the Cogen/Trigen is usually linked to an industrial process generation, levels remained constant throughout the year at a capacity factor of between 45 to 55%.

Figure 16: Summer Peak Cogen/Trigen Profile



A2.5 Customer Segment Load Profiles

A2.5.1 Residential

The AEMO Net System Load Profiles [27](NSLP) were used as the basis for the residential demand profiles for that customer category within a DNSP supply area. The NSLP provides interval consumption data on a half hourly basis.

Table 15 below shows the mapping of each NSLP to its DNSP.

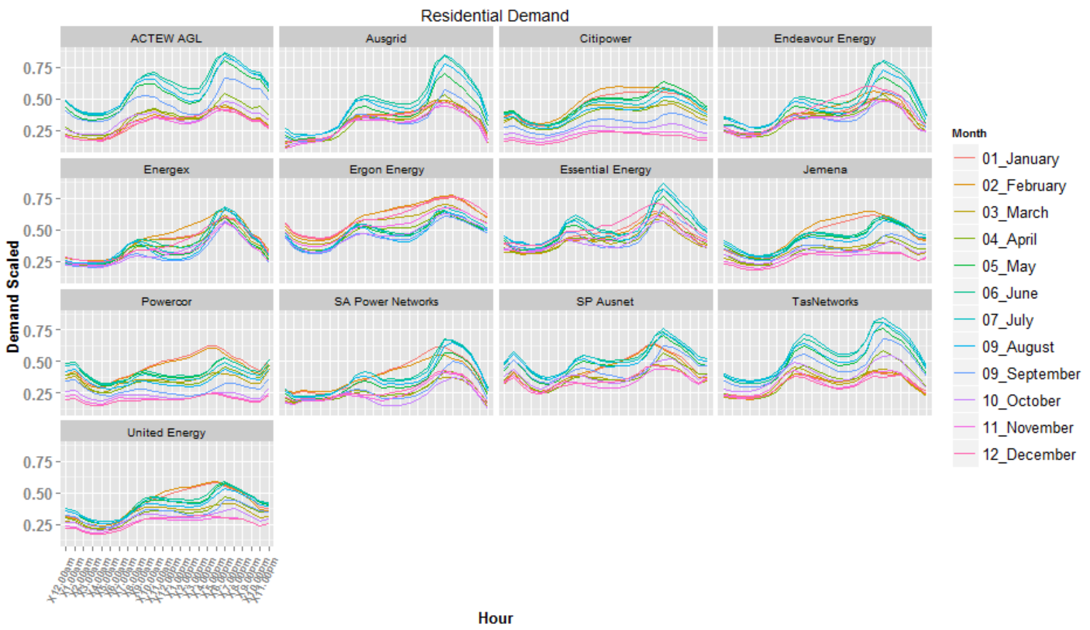
Table 14: List of AEMO Net System Load Profiles by DNSP

AEMO Net System Load	DNSP
ACTEWAGL	ActewAGL
AURORA	Aurora Energy
CITIPOWER	CitiPower
COUNTRYENERGY	Essential Energy
ENERGEX	Energex Limited
ENERGYAUST	Ausgrid
ERGON1	Ergon Energy
INTEGRAL	Endeavour Energy
POWERCOR	Powercor
TXU	SP Ausnet
UMPLP	SA Power Networks
UNITED	United
VICAGL	Jemena

[27] http://www.aemo.com.au/Electricity/Data/Metering/Load-Profiles

The daily metered demands were then scaled to the DNSP maximum demand for the year. Once scaled the demands were split into Weekdays and Weekends/Public holidays. The data was then aggregated for each month and split into two separate tables: one for weekdays used in the peak periods; and the other for weekends used for energy tariffs.

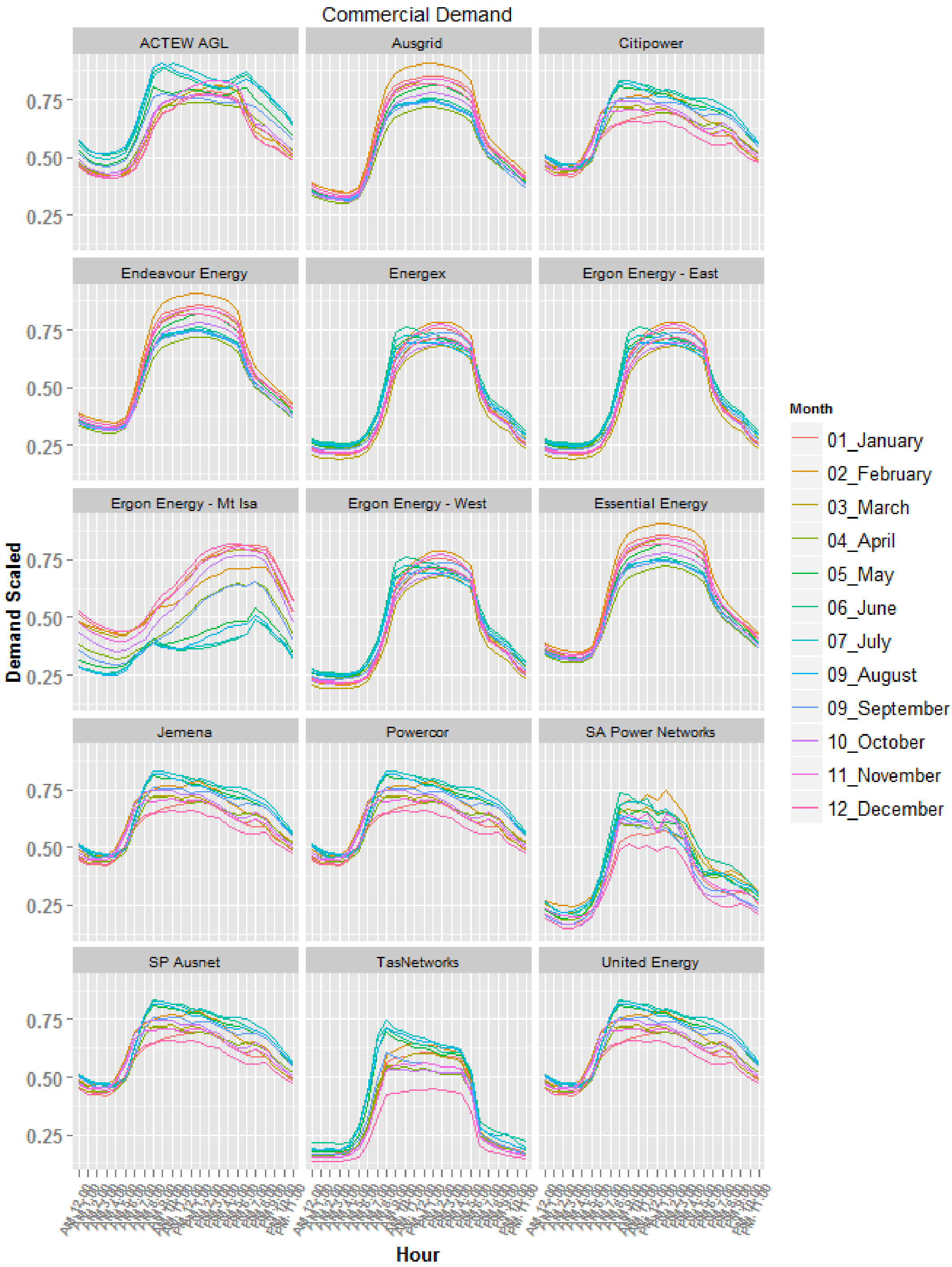
Figure 17: Residential Load Profiles, by Month and DNSP Supply Area



A2.5.2 Commercial

The daily demand traces for commercial loads were constructed using half hourly substation demand data provided by each DNSP. The individual substations used for the commercial trace were based on those regions known to have mainly commercial and/or industrial customers. As with the residential demand load profiles, the data was further segmented into Weekdays and Weekends/Public holidays.

Figure 18: Commercial Load Trace Based on Interval Data for Zone Substations



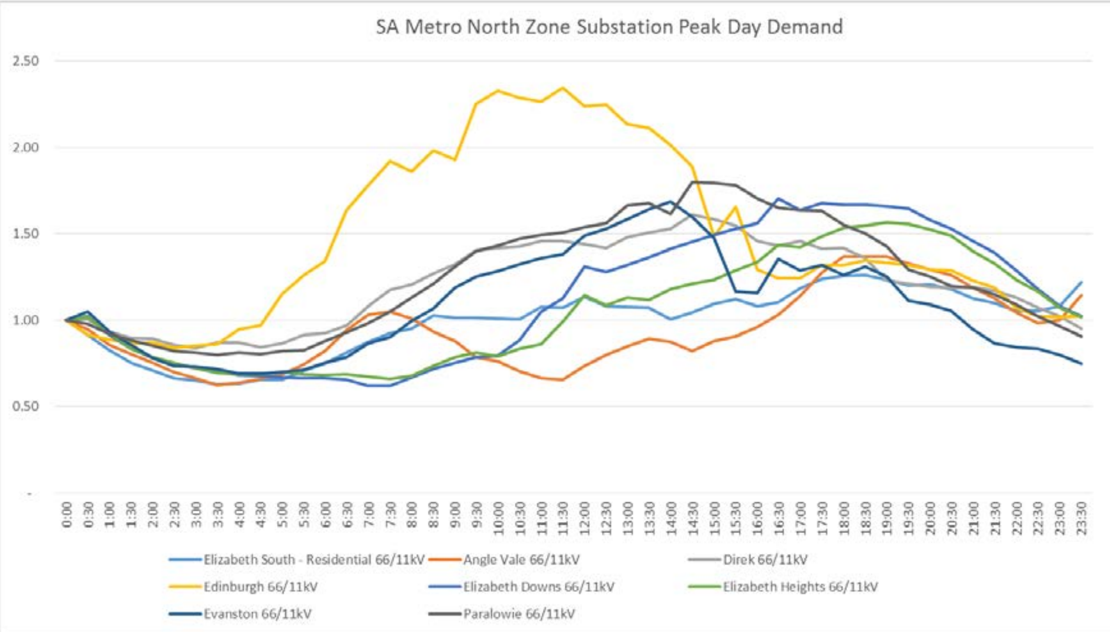
Annexure 3: Analysis of Peak Demand Periods in Selected DNSP Supply Regions

In this section we provide analysis of peak demand periods in both South Australia and the Ergon Energy supply region. The reason for choosing these regions is because these regions have a high penetration of residential and commercial PV which may have changed the peak demand periods in summer for various network assets in each region. This is important for this study since a high penetration of PV may have already resulted in the peak demand shifting from early afternoon hours (2 PM to 4 PM) to late afternoon and early evening (4 PM To 9 PM). This implies that the benefits of PV may not be substantial in reducing network peak demand in these regions, since solar output will be low on average over the period 4 PM to 9 PM. However, it does imply that battery storage will be more important in the future in helping to reduce network peak demand if PV output is stored for use at peak times.

A3.1 South Australia

Figure 19 shows the load profile for various zone substations in the North Metro region of South Australia. While Edinburgh has a commercial customer load profile, most other zone substations have a typically residential profile with peak demand occurring after 4 PM on summer weekdays. Out of the 8 zone substations selected, three had peak days in winter months (Angle Vale[28], Elizabeth South – Residential and Edinburgh), with the remainder all having peak days in either January or February.

Figure 19: Peak Day Demand for Selected Zone Substations - South Australia



Source: http://www.sapowernetworks.com.au/centric/industry/our_network/zone_substation_data_v1.jsp

28 Angle Vale has a PV penetration of 65%, which implies that PV systems have changed the peak demand on this zone substation from summer to winter periods.

Notes: Load in the 0:00 or 12 AM half hour period set to 1 for each zone substation peak day.

A3.2 Northern Queensland

Table 16 provides a list of zone substations in the Ergon Energy supply region, the predominant connection type to low voltage lines that feed the zone substation, and the day in 2013/14 on which the peak demand is recorded. As shown, almost all peak days occur in summer (Nov to Feb), with a peak day occurring in May for the Highfields zone substation (predominantly residential connections).

Table 15: Selected Zone Substations in Northern Queensland (2013/14) - Peak Day

Zone Substation Name and Voltage	Predominant Connection Type	Max day
ALST Alfred Street - 33/11kV	Commercial / Residential	26-Nov-13
BILO Biloela - 11kV	Residential	22-Jan-14
BORE Boyne Residential - 66/11kV	Residential	6-Jan-14
BUCE Bundaberg Central - 66/11kV	Commercial / Residential	18-Mar-14
CACI Cairns City	Commercial	27-Nov-13
CARI Cape River - 11kV	Residential	24-Jan-14
CETO Central Toowoomba - 33/11kV	Commercial	21-Jan-14
CLER Clermont - 11/22kV	Residential	4-Jan-14
COOK Cooktown - 66/22kV	Commercial	19-Feb-14
EMER Emerald - 66/22kV	Residential	5-Jan-14
GLNO Gladstone North - 132/66kV	Commercial / Industrial	19-Jan-14
HIGH Highfields - 33kV/11kV	Residential	7-May-13

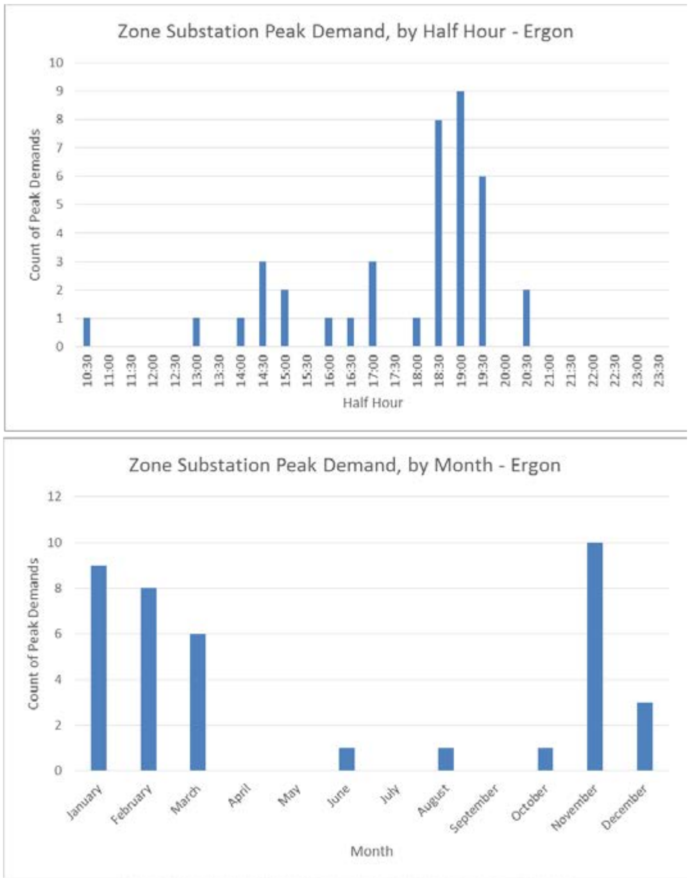
The interval for the peak day and the average day in each zone substation are shown in Figure 21. Some key observations from the data include the following:

- Commercial zone substation load profiles have a long peak period extending from around 10 AM to 5 PM on working weekdays in summer.
- Mixed commercial and residential zone substations also have a similar load profile to commercial zone substations, with the morning peak period more pronounced.
- The industrial zone substation (Gladstone) has a relatively flat load profile – which is similar to other industrial profiles that Marsden Jacob have reviewed.
- Residential zone substations are typically peaking after 6 PM on a summer weekday.

Figure 20 shows the distribution (histograms) of peak demand for 39 zone substations in the Ergon Energy supply region. What this shows is that peak demand typically occurs between 6.30 PM and 7.30 PM on working weekdays in summer (November, January, February and March).

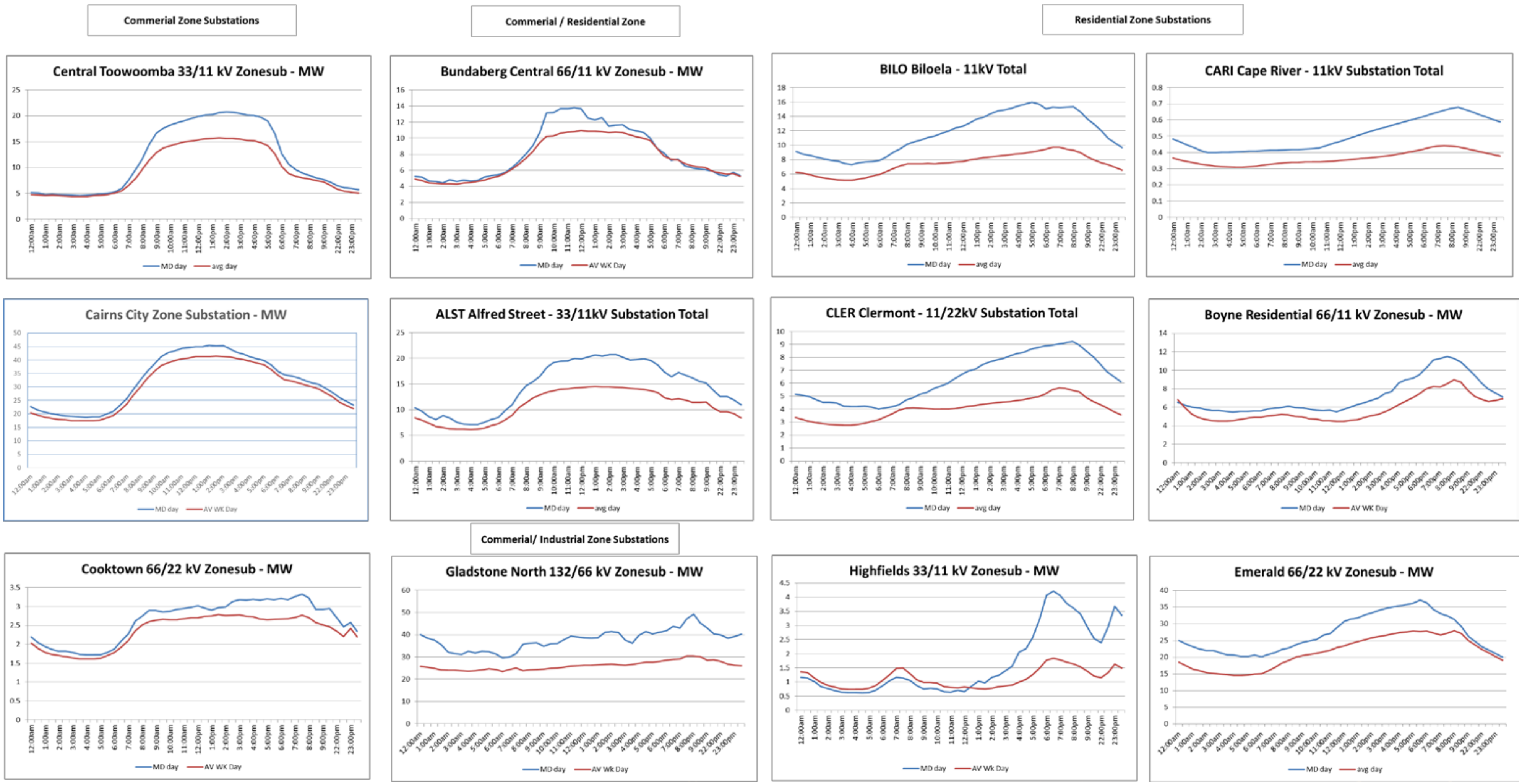
This analysis suggests that the peak period for residential PV systems for this study should be between 4 PM and 9 PM on working weekdays in summer months.

Figure 20: Zone Substation Peak Demand Interval (working weekdays) and Season



Source: Ergon Energy Distribution Annual Planning Report 2015-16 to 2019-20

Figure 21: Northern Queensland Zone Substation Interval Data - Peak Day and Average Day



Annexure 4: Indicative DNSP Network Credit Prices

Table 16: Network Credit Pricing Structures, Monthly Peak Credit Method

Actew AGL	Units	Value
Residential - LV	$/KW/day	0.87
Small Business - LV	$/KW/day	0.90
Large Business - LV	$/KVA/day	0.37
Large Business - HV	$/KVA/day	0.21
Sub-transmission	$/KVA/day	0.17

AusGrid	Units	Value
Residential - LV	cents/kWh	30.52
Small Business - LV	$/KVA/day	1.93
Large Business - LV	$/KVA/day	2.00
Large Business - HV	$/KVA/day	0.89
Sub-transmission	$/KVA/day	0.45

CitiPower	Units	Value
Residential - LV	$/KW/day	1.39
Small Business - LV	$/KW/day	1.66
Large Business - LV	$/KVA/day	0.34
Large Business - HV	$/KVA/day	0.24
Sub-transmission	$/KVA/day	0.52

Energex	Units	Value
Residential - LV	$/KW/day	1.16
Small Business - LV	$/KW/day	1.20
Large Business - LV	$/KVA/day	0.30
Large Business - HV	$/KVA/day	0.28
Sub-transmission	$/KVA/day	0.31

Ergon Energy - East	Units	Value
Residential - LV	$/KW/day	10.56
Small Business - LV	$/KW/day	11.13
Large Business - LV	$/KW/day	0.92
Large Business - HV	$/KW/day	0.59
Sub-transmission	$/KVA/day	1.39

Ergon Energy - Mt Isa	Units	Value
Residential - LV	$/KW/day	10.55
Small Business - LV	$/KW/day	11.12
Large Business - LV	$/KW/day	0.92
Large Business - HV	$/KW/day	0.00
Sub-transmission	$/KVA/day	0.00

Ergon Energy - West	Units	Value
Residential - LV	$/KW/day	25.28
Small Business - LV	$/KW/day	26.64
Large Business - LV	$/KW/day	9.64
Large Business - HV	$/KW/day	6.01
Sub-transmission	$/KVA/day	2.57

Jemena	Units	Value
Residential - LV	$/KW/day	1.22
Small Business - LV	$/KW/day	0.38
Large Business - LV	$/KVA/day	0.17
Large Business - HV	$/KVA/day	0.11
Sub-transmission	$/KVA/day	0.32

Powercor	Units	Value
Residential - LV	$/KW/day	1.44
Small Business - LV	$/KW/day	1.70
Large Business - LV	$/KW/day	0.57
Large Business - HV	$/KW/day	0.44
Sub-transmission	$/KVA/day	0.55

SA Power Networks	Units	Value
Residential - LV	$/KW/day	1.36
Small Business - LV	$/KW/day	1.44
Large Business - LV	$/KW/day	0.74
Large Business - HV	$/KW/day	0.52
Sub-transmission	$/KVA/day	0.55

SP AusNet	Units	Value
Residential - LV	$/KW/day	1.15
Small Business - LV	$/KW/day	1.21
Large Business - LV	$/KW/day	0.00
Large Business - HV	$/KW/day	0.00
Sub-transmission	$/KVA/day	0.37

United Energy	Units	Value
Residential - LV	$/KW/day	1.48
Small Business - LV	$/KW/day	1.22
Large Business - LV	$/KW/day	0.42
Large Business - HV	$/KW/day	0.29
Sub-transmission	$/KVA/day	0.32

Endeavour Energy	Units	Value
Residential - LV	cents/kWh	8.28
Small Business - LV	cents/kWh	11.31
Large Business - LV	$/KVA/day	0.33
Large Business - HV	$/KVA/day	0.09
Sub-transmission	$/KVA/day	0.20

Essential Energy	Units	Value
Residential - LV	cents/kWh	27.56
Small Business - LV	cents/kWh	22.90
Large Business - LV	$/KVA/day	1.37
Large Business - HV	$/KVA/day	0.81
Sub-transmission	$/KVA/day	0.31

TasNetworks	Units	Value
Residential - LV	$/KW/day	0.82
Small Business - LV	$/KW/day	0.78
Large Business - LV	$/KW/day	0.31
Large Business - HV	$/KW/day	0.37
Sub-transmission	$/KVA/day	0.23