Potential effectiveness of an LGNC price signal

prepared for:
City of Sydney

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DOCUMENT INFORMATION

Project	Potential effectiveness of an LGNC price signal
Client	City of Sydney
Status	Final report
Report prepared by	Lance Hoch (lhoch@oakleygreenwood.com.au) Rohan Harris (rharris@oakleygreenwood.com.au)
Date	17 August 2016

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1. Objective of Assignment

As part of its consultation process on the LGNC Rule Change Request that was put forward by the City of Sydney, the Total Environment Centre and the Property Council of Australia, the AEMC is seeking information on the likely effectiveness of the proposed LGNC in changing local generator behaviour so as to result in a predictable increase in local generation at times pre-identified by networks, presumably in response to network congestion.

2. Approach

This investigation of the potential effectiveness of the Local Network Generation Credit (LGNC) is comprised of two major parts:

- modelling of the potential magnitude of the LGNC in a specific network area and the incremental impact of that value on the expected revenue from an intermittent local generation source (a rooftop PV system) and a callable local generation source (a rooftop PV system with battery storage), and
- information on the impact of Orion Energy's export and generation credits – which are quite similar to the LGNC -- on distributed generation within its distribution service area.

3. Modelling of the likely magnitude of the LGNC in a specific network area and its impact on the expected revenue of embedded generation

3.1. Overarching basis of the assessment

The overarching basis of this assessment is as follows:

- The magnitude (absolute monetary) value of the LGNC price signal should be linked to the economic benefit received by a distribution business from distributed generation,
- The best approximation of that economic benefit is the distribution business' Long Run-Marginal Cost (LRMC) of supply, and
- The potential impact of the LGNC on a customer's consumption and/or investment decisions, is assumed to be a function of the incremental net present value (NPV) of the benefits stemming from the application of the LGNC relative to the NPV of the financial benefits stemming from investing in a PV system, or PV and battery system.

3.2. Caveats

There are a number of caveats to the analysis presented in this report. These are:

- We have limited our assessment to two distributed technology options: an intermittent local generator (a rooftop PV system) and a callable local generator (a rooftop PV system with battery). An advantage of the use of PV as the example of a local generation source is that there is measured data on its output profile as well as the average consumption profile of residential customers on a geographic basis. This data allows construction of the hourly availability of PV generation for either (a) offsetting residential consumption, or (b) exporting energy either directly to the grid or to storage located on the customer side of the meter for later export or to offset consumption from the grid. There is also data available on the cost of these systems in a typical residential application.

Together these data allow calculation of how the revenue from an LGNC would affect the financial returns available from these systems, and therefore the likelihood that it would increase (a) customers with such systems seeking to use them in ways that maximise export at times when it is of value to the network, or (b) the take-up of systems that are configured in such a way as to optimise their ability to respond to such a price signal.

Obviously, the LGNC will also apply to other distributed technologies – such as cogeneration – and the impact of the LGNC on the overall financial benefits accruing from investing in and optimising the operation of those other technologies may be very different to PV and PV/battery combined.

- We have only undertaken the analysis for the Endeavour Energy region in NSW. This is considered to be a reasonably representative region in terms of it consumption profile, yet it will produce relatively conservative results because Endeavour Energy's LRMC appears to be lower than most other distribution businesses operating in the NEM. As a result, the value of the LGNC used in this analysis is likely to be lower than that in most distribution service areas within the NEM. This means that the results of this analysis are likely to be a conservative representation of the impact of the LGNC in the NEM as a whole.

  There are two situations in which this may not be the case, however:

  - If the distribution system is winter peaking – this issue is discussed in detail in later sections of the report.
  - If there is a ToU tariff in place that has a material difference in peak and non-peak prices – as this may increase the returns from the use of the PV or PV/battery system as compared to the situation in which a flat tariff is in place. This would reduce the financial return available through the addition of an LGNC based on LRMC in percentage terms, but not in absolute dollars, assuming the absolute value of the LGNC remained the same in both cases.

- We have not modelled the sensitivity of the financial benefits to changes in certain policy settings, for example, changes to feed-in tariff rates, or changes to the structure or level of retail electricity prices.

- We have not taken into account the impact that avoided TUoS payments could have on the financial attractiveness of small-scale distributed generation systems in the event that those payments were to be made available.

  DNSPs are required to pay an embedded generator avoided TUoS payments in accordance with the obligations detailed in Schedules 55.4AA(a)(2) and 5.5 (h)(i)(j) of the National Electricity Rules.

  The LGNC Rule change proposal noted that avoided TUoS payments are unlikely to be accessible to many small-scale local generators who export energy into the grid. This is due to the requirement that the embedded generator be a Registered Generator in accordance with AEMO's definition and rules regarding that role, and the level of transaction and administrative costs associated with this status.

However, the absolute level of these avoided TUoS payments can be material. For example, while the average monthly demand charge at Endeavour's connection points with TransGrid's transmission system for 2016-17 is $1.56/kW, with a maximum of $2.56 and a minimum of $1.25, the averages for the other NSW distribution systems are significantly higher (Ausgrid, $3.32; Essential Energy, $4.31; and ActewAGL, $2.40)[1].

Although the LGNC Rule change proposal did not seek to include the value of any avoided TUoS payments that result from the export of energy by small embedded generators at the time of maximum monthly demand at the closest bulk supply point, it is clear that the export of these generators can have the effect of reducing the amount the DNSP is charged by the TNSP at those times.

- We also did not consider the potential impact of the LGNC on the orientation of new PV arrays. Because network peak demands most often occur in the late afternoon or early evening, an LGNC that provides a payment for export at that time could theoretically incentivise customers to orient new PV arrays to the west to increase PV energy production and export at those times[2].

3.3. Summary of methodology

The methodology we have used to estimate the strength of the LGNC price signal and the potential impact of that price signal is summarised below:

- We determined the half-hourly consumption profile of the average residential customer in Endeavour Energy's area. This was based on applying Endeavour Energy's 2014 Net System Load Profile (NSLP) to its average residential consumption (excluding hot water),
- We determined the generation profile for a typically sized (4kW) PV system [3]. The profile was based on analysis of information from the Australian Photovoltaic Institute (energy/capacity by half hour period in NSW for a large selection of days across the four seasons)[4].
- For every half hour of the year, we then modelled:
  a) Consumption – assuming the 'average' Endeavour Energy residential customer did not own a PV system.

1 *Transmission Prices 2016-17.pdf*, available at https://www.transgrid.com.au/what-we-do/our-network/our-pricing/Pages/default.aspx. Note that these charges would need to be multiplied by the applicable TLF and DLF to calculate the avoided TUoS payment.

2 The value of such an approach was demonstrated by SP AusNet (now AusNet Services) in a paper presented at 2012 Smart Utilities Australia New Zealand conference. A copy of the paper is available at www.engerati.com/sites/default/files/Rohan%20Harris.pdf. See particularly slides 7 through 10.

3 This is broadly reflective of the average size of systems currently being installed.

4 This profile was found to be reasonable when cross-checked against two other sources: (a) a bottom-up build of the theoretical generation of a PV system, and (b) examination of previously published AEMO information on the average kWh/kW generated by a solar panel in NSW.

b) Displaced consumption[5] – assuming the 'average' Endeavour Energy residential customer had installed a 4kW PV system[6],

c) Export energy[7] – assuming the 'average' Endeavour Energy residential customer had installed a 4kW PV system,

- We then also modelled[8] the impacts of adding a 7kWh battery[9] to the above PV system. This allowed us to estimate the amount of:

  d) charge in the customer-side battery for every half-hour of the year,

  e) energy used on site from that battery every half-hour of the year, and

  f) energy exported to the grid every half hour of the year[10].

For a PV-only customer (i.e., using data from items *a* through *c* above), we then estimated:

- the financial benefit that would accrue to the PV customer, assuming that the customer **could not access the LGNC**, with this financial benefit comprising:
  - the reduced retail bill resulting from the PV system displacing network-provided energy. This was based on Origin Energy's 2015/16 Residential Standing Offer Variable Charge (approximately 24 c/kWh for flat rate charges) multiplied by the amount of displaced energy (item *b* from above), and
  - the value of energy exported to the grid given current feed-in tariff levels (for energy). This was derived using a 5c/kWh feed-in tariff[11], multiplied by the amount of export energy (item *c* from above).
- We then added the economic benefit of applying a cost-reflective LGNC to the above benefits. We did this by undertaking three different scenarios to reflect different amounts of energy that could potentially be exported to the grid in response to the LGNC price signal. These scenarios were as follow:

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5 This is simply the amount of consumption that would be provided by the customer's PV system, instead of from the distribution network. This is calculated by deducting the PV generation from the residential load (up to the maximum of the load) for each 30-minute interval of a full year.

6 Systems of this size are very commonly installed.

7 Energy is exported in any 30-minute interval in which residential load less PV generation is a negative number. Total export energy is the absolute value of the sum of those values over a full year.

8 In simple terms, the modelling is undertaken as follows: if (PV generation > load in a half hour period, charge battery unless battery is full (then export to grid), if load > PV generation, use battery if there is charge in battery).

9 A number of the battery storage units currently on the market – including Tesla's PowerWall – are 7kWh.

10 This occurs when the battery is fully charged, and the customer's generation exceeds their load in a half-hour period.

11 For example, the Independent Pricing and Regulatory Tribunal (IPART) set the benchmark range for voluntary solar feed-in tariffs for 2015-16 at 4.7 to 6.1 c/kWh. IPART has also made a Final Determination that the mandatory contribution from electricity retailers to the NSW Government should be 5.2 c/kWh of PV electricity exported by Solar Bonus Scheme customers.

See http://www.ipart.nsw.gov.au/files/sharedassets/website/trimholdingbay/media_release_-_final_report_-_solar_feed-in_tariffs_for_2015-16.pdf

- A customer with a PV system who makes **no change to their consumption profile** in response to the LGNC. We undertook this calculation by ranking each day of the year in order of the overall maximum half hourly peak demand that was assumed to occur on that day (i.e., 1 to 365, based on Endeavour Energy's NSLP), and then calculating the average amount of energy that was exported on the top 10 ranked days between 4pm and 5pm, on the assumption that energy exported during this period will coincide with when Endeavour Energy's system is likely to peak[12], and hence, when a cost-reflective LGNC would apply[13].
- A customer with a PV system who **reduces their consumption entirely in response to the LGNC**. This effectively means that 100% of the energy that is generated from the customer's PV system is exported to the grid at times of overall system peak demand (which is when the LGNC is assumed to apply). This was based on a theoretical assessment of the amount of energy that could be produced between 4pm and 5pm in summer from a 4kW system. This is based on an average peak-day capacity factor of 28.94%[14].
- A customer with a PV system who **adjusts their consumption profile somewhat** in response to the higher opportunity cost of consuming energy during the periods when the LGNC applies. We modelled this level of consumption reduction by reference to the amount of their consumption in those hours in days ranked 11 through 20 (in order of overall maximum half hourly peak demand)[15]. Because days 11 through 20 represent lower levels of consumer demand than days 1 through 10, this will result in more export than would be the case if the LGNC had no effect on their consumption. We then determined the average amount of energy that was exported on these days between 4pm and 5pm on the assumption that energy exported during this time period will coincide with when Endeavour Energy's system will peak, and hence, when a cost-reflective LGNC would apply.

- The results of each of the three different scenarios were multiplied by the assumed benefit to Endeavour Energy's network of not having to transport energy through their HV and sub transmission networks on those peak demand days - with this benefit assumed to be the basis for the LGNC. The value of that benefit was based on Endeavour Energy's most recent, published LRMCs (in their recent Tariff Structure Statement[16]). The only adjustments that we made were to:

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12 This discussion is based on Endeavour's system-wide peak demand, which would be used in conjunction with an LGNC based on the system-wide LRMC. It is important to note that in the Endeavour network (as in most networks) individual local areas on the network may experience peak demand in different seasons or at different times of day within the same season. However, addressing these spatial issues is beyond the scope of this paper.

13 The 2014 year was used for ordering the days with reference to the level of residential demand and for the timing of peak demand on the Endeavour Energy distribution system.

14 Calculated from APVI data.

15 That higher level of incremental export results because we assume that the available solar resource is the same on days 1 through 20, but average residential consumption is lower on days 11 through 20 as compared to days 1 through 10, and therefore incremental export due to a reduction in consumption will be higher on days 11 through 20 as compared to days 1 through 10.

16 Endeavour Energy, *Tariff Structure Statement*, 27 November, 2015, page 69

- Only include in the benefit calculation the LRMC for the HV connection (which is assumed to also include the sub transmission LRMC), on the assumption that exported energy will not reduce the demands that are placed on the LV system[17], hence there will be no economic benefit attributable to the LV network from using distributed generation as compared to a centralised generation source. This 'adjustment' is entirely consistent with the approach proposed in the LGNC Rule change.
- Adjust the published LRMCs by an assumed power factor of 0.9[18], to convert them from annualised kVA figures to kW figures.

In addition to the above, we ran one more scenario, which assumed that an 'average' customer with a PV system also made an investment in a 7kWh **battery**. To model the financial ramifications of this decision, we estimated:

- the financial benefit that would accrue to the customer, assuming that the customer **could not access the LGNC**, with this comprising:
  - The reduced retail bill as a result of the PV system displacing on-site energy. This was based on Origin Energy's 2015/16 Residential Standing Offer Variable Charge (approximately 24 c/kWh for flat rate charges) multiplied by the amount of displaced energy (item *b* from above),
  - The reduced retail bill as a result of being able to use energy from the battery to displace household consumption (from item *e* in the list above) multiplied by the retail rate that would be paid for that consumption, and
  - Energy exported to the grid (item *f* in the list above) multiplied by an assumed export rate of 5c/kWh.
- We then added the economic benefit of applying a cost-reflective LGNC to the above benefits. We did this by assessing how much energy was, on average, contained in the battery on the top 10 ranked days (i.e., ranked by maximum half hourly consumption) between 4pm and 5pm (item *d* from the list above), on the assumption that the battery could export all of that energy directly into the network[19] during this period when the LGNC is likely to apply.

3.4. Summary of results

Table 1 on the following page summarises the results.

17 The underlying assumption here is that the distributed generation source is connected to the LV network.

18 This is consistent with the adjustment Endeavour Energy adopts in their Tariff Structure Statement (see page 70). The adjustment is made by multiplying the kVA figure by the reciprocal of the power factor.

19 In reality, the battery might be used to service a customer's internal demands first, with any residual energy stored in the battery after servicing these internal demand being exported back into the network. If this occurred, this would reduce the benefits by around a 1/3, but with the offset being that this would reduce a customer's own internal consumption during times of system peak demand. If a cost-reflective network tariff (CRNP) were in effect, this is likely to be the most financially attractive option for the customer (because the CRNP should generally be higher than the LGNC, due to the inclusion of the LV network in the CRNP).

Table 1: Results

PV and battery modelling scenario	NPV@5%, 20 years	% increase in NPV of distributed generation benefits stream
A customer with only a PV system who makes no change to their consumption profile in response to the LGNC	$20.74	0.23%
A customer with only a PV system who slightly adjusts their consumption profile in response to the LGNC	$91.24	1.01%
A customer with only a PV system who reduces their consumption entirely in response to the LGNC	$437.60	4.85%
A customer who owns both a PV system and battery and uses the battery to maximise export in response to the LGNC	$2,645.29	18.38%

Source: OGW

The key implications of the above results are:

- If an 'average' Endeavour Energy customer only has a PV system, and does not change their consumption behaviour, and the timeframe over which the LGNC applies is both short (1 hour), and occurs in the late afternoon/early evening (4pm-5pm), then the effective strength of the LGNC to the end customer is likely to be minimal. However, if the period were to be expanded to say include the 3pm to 4pm time period (or even more hours), this would materially increase the effective strength of the LGNC to customers who have installed (or are considering the installation of) a PV system[20]. This reflects the fact that (a) the amount of energy produced from a PV system is materially higher in these earlier hours, and (b) consumption is generally lower in these earlier hours, and hence (c) the amount of energy exported is higher,
- If a customer with a PV system slightly adjusts their consumption profile in response to the LGNC to reflect the fact that the opportunity cost of consumption is now higher as a result of the LGNC, the magnitude of the LGNC benefit increases 4.5-fold (relative to the previously mentioned scenario). That said, in NPV terms, the dollar magnitude of the LGNC is still relatively small in the context of the overall stream of benefits that accrue to a customer who installs a PV system (given current policy and price settings)[21].

20 It should also be noted that a wider LGNC time period might also offer a benefit to the network business in that it could reduce energy at risk (as compared to simply peak demand). The Victorian DNSPs are required to use energy at risk as the key indicator of the need for augmentation, and certain other DNSPs also consider this factor. A wider window would also reduce the likelihood that peak demand periods would be overly volatile to the export of distributed generators.

21 Obviously, changes in these settings (e.g., retail tariff structures or levels, or feed-in tariff levels) would change the underlying benefits of installing a PV system, which in turn would change the relative materiality of the LGNC.

- If a customer with a PV system eliminated all consumption in the time periods when the LGNC applied, the financial benefits would be material (4.85% of the overall benefits of installing a PV system, or $437 in NPV terms). The probability that actual outcomes might approach this level are likely to increase the smaller the window over which the LGNC applies. For example, if the LGNC were to apply to exported energy between 4-5pm on say 5 days a year that were nominated a day in advance (analogous to a critical peak demand tariff), then customers could reap this benefit by ceasing consumption for only 5 hours a year.
- If a customer combines a PV system with a battery, then the potential impact of the LGNC increases significantly, such that the LGNC could increase the financial benefits of installing a PV and battery system by 18%. The reason for this is quite simple – the LGNC allows the owner to monetise the peak-lopping benefits of their beyond-the-meter battery technology. In the absence of the LGNC price signal, customers would likely not discharge their battery to support the network at times of system peak demand[22]; rather, they would be more likely to choose to discharge the battery as normal so as to reduce their own internal consumption requirements to reduce their overall retail bill[23].

  Importantly, these results also indicate the relative value of an LGNC to a callable source of distributed generation (represented by the PV and battery system) as compared to an intermittent one.

Two final considerations are worth noting:

- One key issue affecting the effective strength of the LGNC to customers who have either a PV system, or PV/battery system is whether the network is a summer or winter peaking network. The modelling above assumes that the network is summer peaking, which is the case for most of the distribution systems within the NEM, at least on a total system basis[24]. However, our modelling indicates that an ‘average’ customer who only has PV will export very little, if any, energy after 3.30pm during winter months. This severely limits the economic benefits accruing to the network business from that PV system (given that the peak will almost certainly be later than this), and therefore, the value of the LGNC price signal to the customer. Furthermore, even if a customer combines a 7kWh battery with a 4kW PV system, the customer is still unlikely to export a material amount of energy into the grid, absent sophisticated equipment to monitor and control their energy discharge from the battery. The reason for this is quite simple – modelling shows that the ‘average’ Endeavour Energy customer fully draws down their battery during the winter period prior to 3.30pm due to higher daytime consumption levels (predominately driven by heating) and lower PV generation. However, sophisticated monitoring and control equipment[25] might allow a customer to use the grid at certain times, even when their battery still has energy available to be discharged,

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22 The exception would be where the owner of the battery can negotiate with the DNSP regarding the provision of that service on an individual basis. This would be unlikely in the case of small customers due to the administrative and transaction costs, unless a Demand Side aggregator were to be involved.

23 It is also the case that the availability of an LGNC could change the optimal sizing of the battery in a PV/battery system. These variations were not modelled within the current scope of work.

24 As a result, a whole-of-system LGNC for these distribution systems would be in effect at the time of their summer peak demand. However, the Rule change proposal leaves it up to the DNSP to propose either whole-of-system or area-specific LGNCs. In the latter case, the LGNC would reflect different time periods in different local areas. This is noted where applicable in the sensitivity analysis provided in the following section.

25 Several parties including Reposit Power are exploring the use of such systems.

thus allowing them to discharge that energy into the grid later in the day when the LGNC applies.

- Similarly, even where the distribution is summer peaking, the time at which the peak occurs is important for the strength of the LGNC for customers with PV systems. As noted above, earlier and longer peak periods will improve the value of the LGNC. However, where the peak occurs later (as has been observed in distribution systems where there is a significant penetration of PV systems without batteries), peak periods tend to occur later in the day. In such a situation, the resulting LGNC will occur at a time at which the PV system is generating very little if any energy, and will therefore provide very little if any incremental value to the customer.

  Importantly, the addition of a battery in such a situation would potentially preserve the value of the LGNC assuming that dispatch of the battery could be controlled to optimise the use of the LGNC price signal[26].

3.5. Sensitivity analysis for different distribution businesses

The following table illustrates the various LRMCs that have been published by network businesses of recent times, along with a comment as to the effect that this might have on the calculations presented earlier in the report[27].

Table 2: LRMCs for other businesses

Business	Values	Comment
Endeavour Energy	Endeavour Energy, Tariff Structure Statement, page 69: • Low Voltage - $133 / kVA / annum • High Voltage - $26 / kVA / annum • Sub transmission - $17 / kVA / annum	Represents the base case discussed in this report.
Ausgrid	Upper range of LRMCs outlined in Ausgrid's Tariff Structure Statement (page 45) • Low Voltage - $164 / kVA / annum • High Voltage - $53 / kVA / annum • Sub transmission - $8 / kVA / annum	Higher upper range than Endeavour Energy's, however, Ausgrid is likely to have a larger number of winter-peaking areas, which would limit the effective strength of the LGNC price signal.
Essential Energy	Aggregated estimates of the LRMC by voltage level are outlined in Essential Energy's Tariff Structure Statement (page 58). • Low Voltage - $315 / kVA / annum • High Voltage - $165 / kVA / annum • Sub transmission - $32 / kVA / annum	Has the highest LRMCs of any of the DNSPs reviewed. Everything else being equal, this should increase the strength of the LGNC price signal.

26 As noted earlier, this could also influence the orientation of new PV installations.

27 Note, however, that these comments are limited to the impact of the absolute value of the LRMC on the returns available to the end customer and do not consider other factors such as differences in solar irradiance in different areas, or the potential impact of tariffs structures other than the flat tariff considered in the modelled results reported above.

Business	Values	Comment
SA Power Networks	Aggregated estimates of the LRMC by business category are outlined in SAPN's Tariff Structure Statement (page 10 of Appendix B). • Low Voltage Residential - $124 / kVA / annum • High Voltage Business - $80 / kVA / annum • Major business (assumed to equate to sub transmission) - $35 / kVA / annum	The SAPN High Voltage LRMC is materially higher than Endeavour Energy's. Everything else being equal, this is likely to increase the strength of the LGNC. SAPN is likely to be predominately summer peaking, and has very good solar irradiance - both of which will increase the effective strength of the LGNC price signal, as compared to the Endeavour Energy region.
Powercor	Estimates of Powercor's LRMC by voltage level (and business category) are outlined in Powercor's Tariff Structure Statement (page 52) • Low voltage residential - $96.6 / kVA / annum • High voltage business - $77 / kVA / annum • Sub-transmission - $9.8 / kVA / annum	Powercor's High Voltage LRMC, when combined with the sub-transmission LRMC, is materially higher than Endeavour Energy's. Everything else being equal, this is likely to increase the strength of the LGNC. Powercor is likely to be predominately summer peaking, and has very good solar irradiance - both of which will increase the effective strength of the LGNC price signal, as compared to the Endeavour Energy region.
Energex	Estimates of Energex's LRMC by voltage level are outlined in Energex's Tariff Structure Statement (page 32). • Low voltage - $10.84 / kVA / month • High voltage - $10.32 / kVA / month • Sub-transmission - $5.032 / kVA / month	Energex's High Voltage LRMC, when converted to an annual figure, and when combined with the sub-transmission LRMC (again, after being annualised), is materially higher than Endeavour Energy's. Everything else being equal, this is likely to increase the strength of the LGNC. Energex's area is likely to be predominately summer peaking, and has very good solar irradiance - both of which will increase the effective strength of the LGNC price signal, as compared to the Endeavour Energy region.

Source: OGW

4. Relevant experience in New Zealand (Orion Energy)

As noted in the Frontier Economics report that was prepared for and submitted as part of the Energy Networks Association response to the LGNC Rule change proposal, Orion Energy in New Zealand "offers export credits for EGs in recognition of the benefits exports provide to its network[28]". It is interesting to note that Orion has a strong track record of innovation in tariff setting, having been the first distribution company in New Zealand to implement dynamic network pricing based tariffs that were remarkably successful in assisting the company in improving its load factor and thereby reducing costs for all customers. Orion's export and generation credits have been in place for about 16 years, and, according to a company representative, were first introduced by the company "as an extension to our price signals in support of demand side management at coincident peak times, [and to] pay for support at other times when it is beneficial for our network management"[29].

28 Frontier Economics, *Valuing the impact of local generation on electricity networks, A report prepared for the Energy Networks Association (ENA)*, February 2015, p 28.

29 Email correspondence from Orion Energy of 20 June 2016.

The Orion export credits share many of the key features of the proposed LGNC, including the export price being based on:

- the network's long-run average incremental cost (LRAIC) adjusted for the fact that "the required size for distribution transformers and low voltage systems is usually unchanged when generation is installed[30]", which is parallel to the proposed LNGC being based on the long-run marginal costs of the voltage level above the voltage at which the embedded generator is connected, and
- the amount of electricity injected into the network by the embedded generator during peak loading periods

It is also interesting to note that Orion's credit:

- allows the customer to choose between (a) a lower anytime credit rate for all kWh of energy export or (b) a higher credit rate for exports at peak times (requiring appropriate time-of-use metering)
- uses information on the average coincidence between export from solar PV generation and network peak demands (which in New Zealand are in the winter) to provide a deemed credit for PV export, and
- includes a component reflecting avoided transmission charges.

Email and telephone correspondence with a representative of Orion Energy was undertaken to assess the impact of the credits. Key findings were:

- The credits have not influenced take-up or use of PV systems in New Zealand for the simple reason that the Orion network experiences its peak congestion periods on winter nights, when PV systems do not generate. To date, no PV/battery installations have participated either.
- But the credits have influenced callable local generation. According to the Orion Energy representative, "The main influence of our credits has been on large customers that have diesel generation for backup. Our credits have encouraged them to maximise output and in some cases to over-size their generation, and export, rather than just meeting their own load". However, the representative also stated that some customers "have specifically invested in response to our pricing".
- The representative estimated that there is a total of about 50MW of callable customer-side generation installed within the Orion network, and the network observes about 15MW of demand reduction from these facilities during peak times, plus a further (approximately) 5MW of export.

5. Conclusion

The objective of this investigation was to quantify, to extent possible, the potential effectiveness of the Local Network Generation Credit (LGNC) in changing local generator behaviour so as to result in a predictable increase in local generation at times pre-identified by networks, presumably in response to network congestion.

30 Ibid

Based on:

- our modelling of the likely impact of an LGNC on the returns to an owner of a distributed generation source that can respond to notification of a network need, using real data from the Endeavour Energy service area, and
- the experience of Orion Energy with its export and generation credits, which are quite similar to the proposed LGNC,

it is reasonable to conclude that the implementation of an LGNC would result in a predictable increase in local generation at times pre-identified by networks, in response to local network congestion.