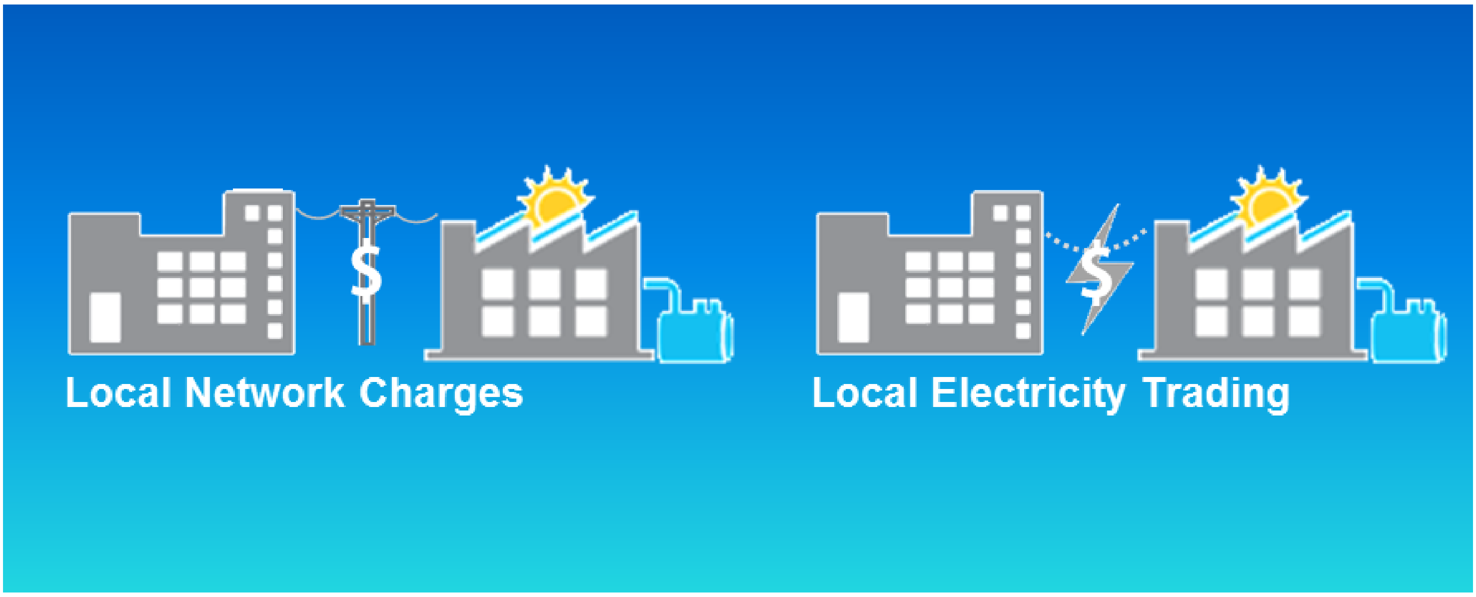


UTS: INSTITUTE FOR SUSTAINABLE FUTURES

ECONOMIC IMPACT ANALYSIS OF LOCAL GENERATION NETWORK CREDITS IN NSW

July 2016

2016

ABOUT THE AUTHORS

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

Authors: Scott Kelly, Jay Rutovitz, Edward Langham and Lawrence McIntosh.

CITATION

Please cite this report as: Kelly, S., Rutovitz, J., Langham, E., McIntosh, L. (2016) An *Economic Impact Analysis of Local Generation Network Credits in New South Wales*. Institute for Sustainable Futures, UTS.

This paper is prepared as part of the ARENA funded project 'Facilitating Local Network Charges and Virtual Net Metering'.

ACKNOWLEDGEMENTS

The authors would like to thank our project and trial sponsors and partners: The Australian Renewable Energy Agency (ARENA), AGL, Byron Shire Council, City of Sydney, Ergon Energy, Moira Shire Council, Local Government Infrastructure Services, NSW Department of Industry Resources & Energy, Powercor, Swan Hill Rural City Council, Total Environment Centre, Wannon Water, Willoughby City Council, Ausgrid, Energy Australia, Essential Energy and Origin Energy; and the additional members of the project Strategic Reference Group: Australian Energy Council, Clean Energy Council, Electricity Networks Association, NSW Office of Environment & Heritage, Property Council of NSW, Victorian Department of Environment, Land, Water and Planning.

We would like to acknowledge the great contribution made to this research by our trial partners; however, the analysis and conclusions are the responsibility of the authors alone.

DISCLAIMER

For further information visit: **www.isf.uts.edu.au**

Contact: Alison Atherton, E: Alison.Atherton@uts.edu.au, T: +612 9514 4909

Institute for Sustainable Futures
University of Technology Sydney
PO Box 123
Broadway NSW 2007

EXECUTIVE SUMMARY

ABOUT THIS REPORT

This work is part of the *Facilitating Local Network Charges and Virtual Net Metering* research project, led by the Institute for Sustainable Futures (ISF) and funded by the Australian Renewable Energy Agency (ARENA) and other partners. The project is investigating two measures aimed at making local generation more economically viable: Local Network Credits for partial use of the electricity network, and Local Electricity Trading (LET) (previously referred to as Virtual Net Metering or VNM) between associated local generators and customers.

In July 2015, the City of Sydney, the Total Environment Centre (TEC) and the Property Council of Australia, submitted a rule change request to the Australian Energy Market Commission (AEMC) for the introduction of a Local Generation Network Credit (LGNC). The economic modelling undertaken for this project provides an analysis of the economic impact of the introduction of an LGNC on overall network costs and consumer bills in the short, medium, and long term in New South Wales.

Other outputs from the project are relevant to consideration of the rule change request, and are available at **www.isf.uts.edu.au**

SUMMARY OF METHOD AND APPROACH

This research developed a novel method for estimating and comparing the long-term economic costs of electricity network expansion under different scenarios in order to understand the economic implications of introducing an LGNC payment to generators. The main characteristics of the model are:

1. The investment in future electricity network infrastructure is estimated using growth projections for the number of consumers, producers and agents who are both producers and consumers (i.e. prosumers) on the electricity network came primarily from the 2015 and 2016 AEMO[1] NEFR[2] reportscombined with derived demand profiles for different users (agents) on the network[3]. We compare the effects of business as usual (BAU) network expansion with the effects of the introduction of a Local Generation Network Credit (LGNC).
2. The model considers four network levels, low voltage (LV), high voltage (HV), sub-transmission (ST) and transmission (TR). Twelve representative agents are defined, including three types of distributed generator and three agent types per customer class (residential, small commercial and large commercial). The characteristics of each agent represent the average for all users belonging to that category.

---

[1] Australian Energy Market Operator
[2] National Energy Forecasting Report
[3] Data for customer numbers and projected growth rates came from the AEMO NEFR 2015, and projections for growth in distributed generation came from the AEMO 2016 NEFR. Additional information came from ESAA 2016 and the APVI solar map.

3. The model applies a multi-level approach that incorporates half-hourly consumption and generation over a 24-hour period for each representative agent for summer, autumn, winter and spring. Aggregate load on the network is then estimated for each scenario based on the total number of agents within each category on each network level.
4. The LGNC will have the effect of increasing the adoption rate of local generation and how it is operated and dispatched at different times. This changes the aggregate demand profile at each network level, and therefore the requirements for future network augmentation. This is represented in the model by increasing the growth rate for the relevant agent categories.
5. PV and storage systems increase significantly in the BAU scenario. However, the potential interaction of an LGNC with penetration rates and dispatch strategies for batteries is not yet well enough understood to model, so the growth is the same in both the BAU and LGNC scenarios in this study.
6. In the LGNC scenario, Local Generation Network Credits (LGNCs) were paid to consumers for generation exported to the grid at peak, shoulder and off-peak periods. The value of the LGNC for different networks was estimated based on a series of trials conducted by ISF.[4] The value of LGNC payments for different networks and billing periods can be viewed in Appendix C.

A number of key assumptions inform the model:

- Network augmentation is not required until 2025 in the BAU scenario, due to spare capacity in the network.[5]
- LGNC payments are not made to existing generators.
- LGNC payments are not made to generators smaller than 10kW.
- There is an 80/20 benefit share of the calculated LGNC paid to local generators (that is, only 80% of the calculated LGNC value is paid to the generator, with the remaining benefit going to the network provider).

OVERALL ECONOMIC BENEFITS

The results of the modelling show that over the long term (to 2050) an LGNC scenario has an **overall cost saving of approximately $1.2 billion, approximately 59% lower than the cost of network expansion under BAU**. Table 1 below shows the net present value (NPV) of the cumulative network investment under each scenario, and the NPV of cumulative LGNC payments in the LGNC scenario.

The graph in Figure 1 below shows the NPV of the annual expenditure in each scenario, with the bars representing the network expansion costs in the BAU scenario and the combined network expansion costs and LGNC payments in the LGNC scenario.

- Over the short term (to 2020) the LGNC scenario incurs a small annual economic cost rising from $1m in 2018 to $6m in 2020 and then becoming an economic benefit in 2025 of $5m.

[4] McIntosh, L., Langham, E., Rutovitz, J. & Atherton, A. (2016) *Methodology for calculating a local network credit*.

[5] When compared with other Australian states, NSW has significant spare network capacity. Therefore, the results presented in this report may be conservative relative to outcomes in other states.

- In the LGNC scenario spare capacity is not exceeded on the transmission network until 2031, on the high voltage network in 2030 and on the low voltage network 2027, representing a delay in network expansion of between two and five years because of more distributed generation coming online.
- Net economic costs and benefits of the LGNC scenario break even in 2025, increasing to $66m annual benefit per year by 2050 compared to BAU (this figure can be estimated from Figure 1 by deducting the costs in BAU from the costs under LGNC). The reduced requirement for network investment occurs because of the reduction in peak load due to the increased local generation incentivised by the LGNC payment

Table 1 Cumulative economic cost or benefit of an LGNC payment (NPV)

	2020	2030	2040	2050
BAU				
Network investment	-	$172 m	$939 m	$2,012 m
LGNC payments	-	-	-	-
Total	**-**	**$172 m**	**$939 m**	**$2,012 m**
LGNC scenario				
Network investment	-	$16 m	$239 m	$598 m
LGNC payments	$6 m	$52 m	$132 m	$233 m
Total	**$6 m**	**$69 m**	**$371 m**	**$832 m**
Net Economic benefit	**-$6 m**	**$104 m**	**$567 m**	**$1,181 m**

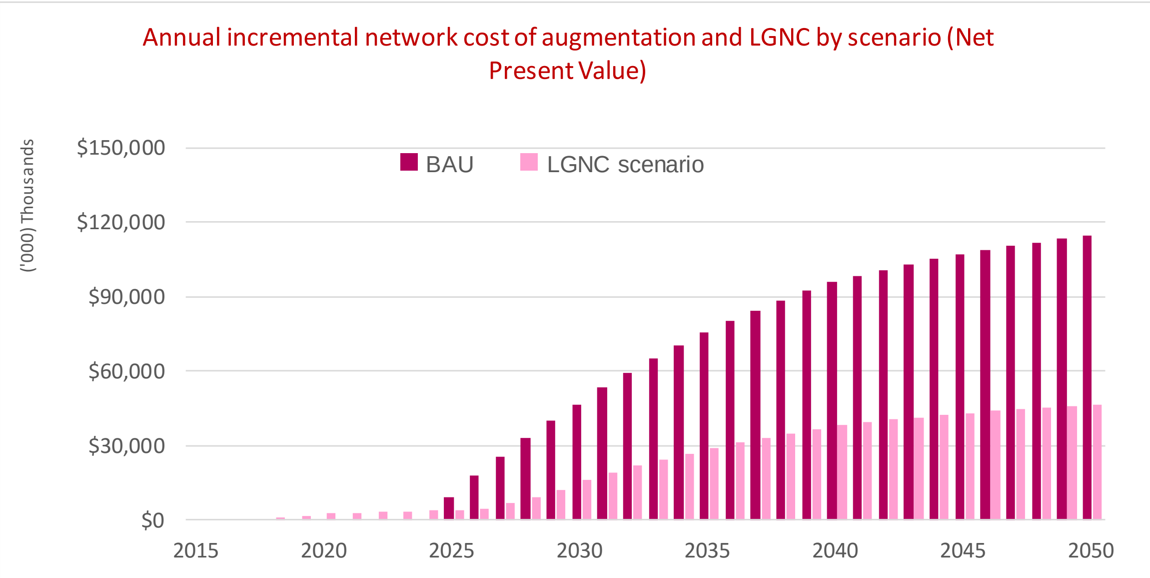


Figure 1: Annual incremental network costs by scenario (NPV)

CUSTOMER BILLS

The impact on annual customer electricity bills is shown in Table 2 below.

In the LGNC scenario compared to BAU over the short term (to 2020), there is no impact on residential sector bills, a modest average increase of $2 per annum in the small commercial sector, and an average increase of $25 in the large commercial sector. By 2030 all consumers are realising savings.

- Small and large commercial customers see significant savings by 2030 relative to BAU, and by 2050 these average $438 and $5,440 per year respectively.
- The average effect on residential customers over the medium to long term remains small, with a projected saving of $6 at 2030 relative to BAU, rising to $15 by 2050.
- Those residential and small commercial customers who do not have PV systems receive the most benefit, as their import requirements are higher.
- Small commercial customers with sufficient generation capacity to export electricity receive benefits of between $184 and $348 in 2030 and 2050 respectively.
- Large commercial customers with generation benefit the most, with savings of $2,889 in 2030 and $3,869 by 2050 relative to BAU. This does not factor in the costs of the generation technology.

Table 2: Net impact of introducing an LGNC on customer bills[6,7]

$ per year	Average	2020	2030	2050
Residential	-$9	$0	-$7	-$20
Residential with PV	-$6	$0	-$4	-$13
Residential with PV + Battery	-$2	$0	-$1	-$4
Total Residential Customers	-$7	$0	-$6	-$15
Small Commercial	-$185	$4	-$139	-$422
Small Commercial with PV	-$127	$3	-$95	-$289
Small Commercial with PV (includes export)	-$211	-$102	-$184	-$348
Total Small Commercial Customers	-$191	$2	-$140	-$438
Large Commercial	-$367	$14	-$276	-$843
Large Commercial with cogen	-$1,239	-$335	-$1,019	-$2,374
Large Commercial with cogen (includes export)	-$3,050	-$2,414	-$2,889	-$3,869
Total Large Commercial	-$2,341	$25	-$1,693	-$5,440

[6] Negative numbers represent reduced bills; positive numbers represent increased bills

[7] Average values by customer level represent the average reduction per bill. As there are different numbers of customers in each representative agent category, the average values are not the arithmetic averages for each customer category (e.g. sum each category and divide by three).

LGNC PAYMENTS ARE NOT A CROSS-SUBSIDY

The LGNC scenario as modelled represents a system-wide economic saving to all consumers, and therefore does not represent a cross-subsidy between different consumers. LGNC payments are estimated from avoided future network expansion costs. A predetermined proportion of these future costs (initially set at an 80% benefit share) is then provided to those agents who install technology which may reduce future network expansion costs. As all consumers benefit from this arrangement, there is no cross-subsidy occurring between different customers on the network.

An LGNC tariff is very different to other tariffs that have been implemented in the recent past such as the FiT (Feed in Tariff) for solar PV. Under the FiT arrangement, there has been an implied subsidy from those consumers who do not own PV to those consumers who do own PV. Under FiT there is no intention to reflect network cost reductions, and therefore no time of use element, or reference to the LRMC in the calculation methodology. An LGNC payment thus represents a net benefit to all customers rather than cross-subsidies occurring between customers.

The majority of the value generated by the LGNC scenario is given to those customers who interact with the network (e.g. consumers and exporters to the grid). Although equity and income distributional effects were outside the scope of this research, it is clear from the proposed structure of LGNC payments that consumers of electricity who do not export are set to benefit substantially from its implementation.

The size of the economic benefit does vary from customer to customer and is a direct function of both the import requirements for different electricity consumers and the value of electricity exported back to the network. Those customers who interact with the grid the most (i.e. those who import and export electricity) receive the most benefit, while those customers who do not import or export anything from the grid receive less benefit. As shown in **Error! Reference source not found.**, residential customers who have higher import requirements from the grid will receive the largest reductions in absolute terms on their electricity bills. This is true even though residential customers are excluded from receiving LGNC payments. This is because the benefits of avoided augmentation are distributed on a volumetric basis for all consumers of grid supplied electricity.

In a scenario of zero or declining peak demand on the network, LRMC will tend to zero, as LRMC values are calculated from projected augmentation. As LGNC values are calculated directly from LRMC values, LGNC payments will also tend to zero. Therefore, in the situation of zero growth in peak demand, both LRMC and LGNC will tend to zero, so the net economic effect of the LGNC payment and the effect on customer bills will be zero.

PEAK DEMAND AND NETWORK UTILISATION

Peak demand on the network is shown to increase more slowly under the LGNC scenario. The largest reductions in peak demand growth are on the transmission and high voltage networks where peak demand is predicted to increase by 22–23% by 2050 under BAU but by only 8–11% under the LGNC scenario. This represents reductions in peak demand of over 50% for the transmission and high voltage networks. The smallest savings are on the low voltage network where peak demand is only 35% lower in the LGNC scenario by 2050.

Furthermore, we show that network utilisation[8] is greater in the LGNC scenario, by between 0.6% in the low voltage network and 1.4% in the transmission network. Our research suggests that the utilisation of the network is highly sensitive to the uptake of batteries where high battery penetration leads to significant increases network utilisation but this is highly dependent on the discharge strategy employed by the operator and the level of exports back into the grid.

Network costs and therefore network utilisation are important components of consumer bills. Network utilisation is indicative of the volume of electricity being transported across the network. For most tariff structures, maintaining utilisation will make it easier to recover network costs.

Table 3: Increase in peak demand on different levels of the network

NETWORK	2015 (MW)	BAU 2050 (MW)	LGNC 2050 (MW)	BAU % Increase	LGNC % Increase	Peak Savings MW (%)
Transmission	11,354	13,883	12,284	22%	8%	1,599 (63%)
High Voltage	11,426	14,093	12,661	23%	11%	1,432 (54%)
Low Voltage	8,299	10,412	9,676	25%	17%	736 (35%)

SENSITIVITY TESTING

We undertook sensitivity analysis on a number of assumptions made in the model, namely:

- the year network augmentation is first required on the network
- the rate of growth of local generation in the LGNC scenario compared to BAU
- the exclusion of making LGNC payments to existing dispatchable, non-dispatchable and small systems under 10kW
- the underlying growth in peak demand on the network
- the effect of including non-locational transmission costs in the LGNC payments.

The outcomes from these sensitivity tests have allowed us to make a number of decisions I regard to how the LGNC could be implemented to maximise its benefits for networks and consumers.

- Firstly, we recommend that an LGNC should not be paid to existing generators. There might be a case for making payments to existing dispatchable generators to incentivise exports to the grid at peak times, but further research is required to understand the costs and benefits of doing so.
- Secondly, we recommend that LGNC payments are not made to systems under 10kW. This excludes all residential solar PV and a significant proportion of commercial PV. Our results show that excluding units under 10kW maximises the benefits for all consumers on the network.
- Thirdly, sensitivity analysis is included for the non-locational component of transmission LRMC estimates. Removing non-locational costs from LRMC calculations does not have a substantive effect on overall economic benefits.

[8] Network utilisation is calculated as actual network load over the maximum possible load on the network

$$Utilisation = \frac{Actual\ Load\ (MWh)}{8760 \times Peak\ Load\ (MW)}$$

Lowering LRMC values does however have the effect of lowering LGNC payments, which will lowers incentives for the uptake of local generation.

Testing the sensitivity of spare network capacity shows that higher values of spare capacity reduce net economic benefits. However, in all cases tested there was a positive economic benefit in the long term and in most cases there is a positive economic benefit in the medium term. We also tested changes to local generation in response to the LGNC. In general, if there is less local generation, the overall economic benefit is reduced, while if there is a greater uptake in local generation than forecast, the economic benefit increases. Economic benefits are reduced if existing generators are paid the LGNC. This effect is much more marked in the short term if payments are made to both non-dispatchable and dispatchable generators.

Finally, sensitivity testing was conducted on the underlying growth in peak demand on the network. There are many reasons why actual demand could vary significantly from current projections – for example, the impact of the introduction of cost reflective tariffs, or the penetration of battery storage. We tested a variation in demand growth as a proxy for all of these factors. The BAU peak demand growth rate averages 0.6%, and we modelled alternative growth rates from 0.04% to 1.1% per year.

Figure 2 shows the variation in net economic benefit according to growth in peak demand. As expected, a reduction in projected growth rates reduces net economic benefit, and if growth rates drop below 0.3% per year there is a cost over the entire period. However, the costs and benefits are asymmetrical, with potential benefits approximately six times greater than potential costs. This asymmetry arises because costs are capped at the LGNC payments, while benefits from avoided network augmentation result from both the exported energy in receipt of an LGNC payment, and associated behind-the-meter generation.

We note that the 2016 NEFR forecast for peak demand growth in NSW averages -0.1% per year for the period 2016 to 2036. This is a significant drop from the 2015 growth projection of a 0.99% per year increase, and has been updated for climate policies which are expected to increase the cost of electricity. However, the updated forecast does not include the effect of electric vehicles, which are also likely to be impacted by climate policy, and will tend to drive peak demand upwards.

We have not modelled a negative growth rate, but once growth drops below 0.2% per year the entire modelled value of the LGNC shows as a cost, as no augmentation is required for the entire period. However, the LGNC costs would in fact be a great deal lower than modelled for this circumstance.

We have not modelled two structural factors which would significantly reduce the costs of the LGNC in a zero or declining growth situation for peak demand. Firstly, when peak demand growth equals zero the LRMC value will tend towards zero. This will have the effect of reducing the LGNC payments towards zero, as they are calculated directly from the LRMC. This also reduces the incentive value, and the likely uptake of new local generation on the network. Neither of these aspects is captured in the modelling, as the LRMC and LGNC are modelled as static values, whereas in reality they would be reset annually.

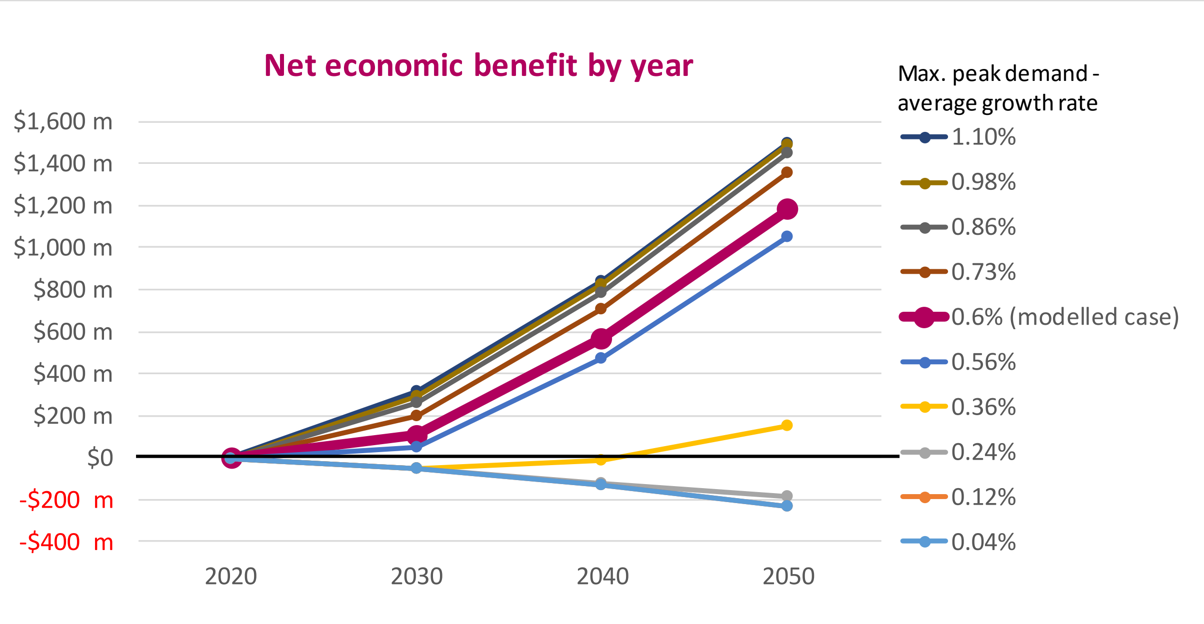


Figure 2: Net economic benefit according to growth rate in peak demand

CONCLUSION

The LGNC scenario incurs lower overall economic costs compared to BAU in the medium and long term, with a smallest cost savings occurring in the short term. **The results show that there is an overall economic benefit to society offered by providing an LGNC payment, with cumulative cost savings in the order of $1.2 b by 2050. These benefits are reflected in a decrease in consumer bills after five to ten years.** This effect is true for all types of consumers, but most marked for commercial customers.

The costs and benefits are highly dependent on the underlying growth in peak demand, with forecasts for growth highly volatile at present. It is recommended that the modelling be repeated with updated forecasts once the projections for electric vehicles are included, as it is likely that these will have a significant impact on demand.

This modelling has resulted in the following design decisions: LGNCs should not be paid to existing non-dispatchable generators, or to generators under 10kW, as excluding them maximises economic benefits to all consumers.

This modelling excluded payments to all existing generators. However, there should be an additional investigation to determine whether incentivising sub-classes of dispatchable generators by giving them an LGNC would result in an overall societal benefit.

FURTHER WORK

The modelling undertaken for this project goes a long way towards demonstrating the economic value of an LGNC. There are however a number of ways that modelling with greater scope could more accurately reflect real conditions, and we recommend that further work be undertaken in order to inform the detailed development of an LGNC to maximise benefits for electricity consumers. We recommend that this work includes the following elements:

1. Model the economic impacts by each network area and separately model sub-regions where growth characteristics are very different.
2. Incorporate dynamic modelling of the LRMC and LGNC values to allow for low or zero growth situations.
3. Re-run the model with an updated projection once electric vehicles have been incorporated into forecasts.
4. Understand and incorporate the impacts of reduced replacement costs corresponding to a downsize in network capacity resulting from increasing local generation. This is particularly important if we are moving into a time of potential reductions in maximum peak demand.
5. Develop a function for the relationship between battery uptake and battery dispatch response to LGNC payments.
6. Investigate the cost/benefit of an LGNC payment to sub-classes of dispatchable generators.
7. Allow feedback within the model to directly influence uptake rates of local generation dependent on the value of the LGNC payment.
8. Implement a probabilistic model for both generation and demand per agent. Profiles currently represent the average behaviour of both consumers and generators, and development of a probabilistic model would more accurately reflect the heterogeneity amongst producers and consumers on the network.
9. Implement a probabilistic model for generation from non-dispatchable sources (solar and wind). This would more accurately reflect the effects of intermittency on the network and the associated impacts on peak demand.

CONTENTS

FIGURES

TABLES

LIST OF ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APVI	Australian Photovoltaic Institute
ARENA	Australian Renewable Energy Agency
AUGEX	augmentation expenditure
CONNEX	connection network expenditure
CAPEX	capital network expenditure
DNSP	Distribution Network Service Provider
HV	high voltage
ISF	Institute for Sustainable Futures
LET	local electricity trading
LG	local generation
LGNC	local generation network credit
LNC	local network credit (or charge)
LRMC	long run marginal cost
LV	low voltage
NEFR	National Electricity Forecasting Report
NEM	National Electricity Market
OPEX	operational network expenditure
PV	photovoltaic
REPEX	replacement network expenditure
ST	sub-transmission
TEC	Total Environment Centre
TOU	time of use
TOTEX	total network expenditure
TR	transmission
UTS	University of Technology Sydney
VNM	virtual net metering

1 INTRODUCTION

This report provides an analysis of the economic impact of the introduction of Local Generation Network Credits (LGNC) on overall network costs, and the consequent impacts and benefits for consumer bills.

The work is part of a one-year research project, *Facilitating Local Network Charges and Virtual Net Metering.* The project is led by the Institute for Sustainable Futures (ISF) and funded by the Australian Renewable Energy Agency (ARENA) and other partners. It is investigating two measures aimed at making local generation more economically viable:

- Local Generation Network Credits (LGNC) (also referred to as local network charges) are payments made to local generators reflecting the economic benefit they provide to the grid.
- Local Electricity Trading (LET) (also referred to as Virtual Net Metering or VNM) refers to the netting off of electricity between associated customers and generators in the same local distribution area.

In July 2015, the City of Sydney, the Total Environment Centre (TEC) and the Property Council of Australia, submitted a rule change request to the Australian Energy Market Commission (AEMC) for the introduction of an LGNC. As part of that proposal, Oakley Greenwood prepared a statement on the likely costs and benefits of the introduction of Local Network Generation Credits for different parties, but those impacts were not quantified. The economic modelling undertaken for this project builds on the work done by Oakley Greenwood and aims to quantify impacts on key stakeholders, primarily electricity consumers and generators, and will be provided to the AEMC as part of the rule change process.

It is clear that providing evidence as to how the measure will promote the National Electricity Objective is essential in order for the AEMC to make a determination. As network price trajectories for customers are important, this is the focus of our economic analysis.

In line with the Rule Change Proposal, the ISF project researches local network charges on the basis of a credit paid to the generator.

The context for this research is that large electricity infrastructure expenditure has taken place in many of Australia’s distribution networks since 2010. The projected growth in electricity demand did not occur, and there have been some years of demand actually falling. Thus in many instances, networks have sufficient capacity to meet expected demand requirements for a number of years to come. However, over the long term, as electricity demand rises, augmentation of the network infrastructure, and the associated expenditure, may once again be required.

A key purpose of the research is to determine whether overall network costs can be reduced through the use of an LGNC to incentivise, and thereby increase, local generation. The current spare capacity means that an LGNC may not defer or avoid much network investment in the short term, but as the amount of local generation on the network increases, this will avoid future expenditure. The research therefore examines the effect of spare capacity on the network and the value of delaying future investment under an LGNC environment. The model estimates the costs of network expansion under an environment of increasing peak demand on annual basis until 2050.

1.1 Aims and research questions

This modelling exercise had several aims, the most important of which were to:

- estimate the long-term economic costs and benefits of future network infrastructure investment and the economic impacts of making LGNC payments, in order to determine whether the introduction of LGNC payments would reduce or increase overall network costs

- model the effects of future network expansion and LGNC payments on customer bills over the short, medium and long terms.

The following research questions are answered by the economic model:

- What are the expected annual costs associated with future network expenditures and Local Generation Network Credits under different assumptions of growth in peak demand driven by different electricity consumers and producers on the network?

- How might growth in coincident peak demand on the network change in aggregate as demand from different consumer profiles changes, particularly with the uptake of local generation and behind-the-meter consumption?

- What are the economic benefits and costs of offering an LGNC payment when compared to business as usual growth and consequent network expansion?

- How will consumer bills be impacted by future network investment and LGNC payments?

- What are the main sensitivities in the economic modelling, and how do these sensitivities impact final results?

It was therefore important that the model was able to account for the following effects:

- growth in peak demand (MW) and consumption (GWh) on the distribution network for off-peak, shoulder and peak billing periods
- the expected growth in peak demand (MW) and consumption (GWh) on different levels of the network including low voltage (LV), high voltage (HV) and transmission (TR)
- changes in the uptake of different local generation technologies over time
- the effects of generation and consumption that may occur behind the meter
- the effects of both dispatchable and non-dispatchable generation technologies
- the economic costs of network expansion taking into consideration augex, opex, and repex expenditure
- the economic costs of making LGNC payments to distributed generators
- the likely time lag between the payment of the LGNC, and when savings would occur, particularly when many parts of the electricity network have surplus capacity.

1.2 The concepts

Local Generation Network Credits

Local Generation Network Credits (LGNC) are payments made to embedded generators for electricity that is produced and consumed within a defined distribution network area. This recognises that the generator is using only part of the electricity network and is potentially avoiding future network investment occurring elsewhere. The LGNC payment therefore reflects the long-term benefit provided by local generation to the network. The rationales for an LGNC are: to address inequitable network charges levied on a generator/consumer pair; to dis-incentivise duplication of infrastructure (private wires) which aim to avoid network charges altogether; and to maintain use of the electricity network.

Local Electricity Trading (LET)

LET is an arrangement whereby generation at one site is “netted off” at another site on a time-of-use basis, so that Site 1 can ‘sell’ or transfer generation to nearby Site 2. The exported electricity is sold or assigned to another site for billing purposes. LET can be applied in different ways:

- A single generator-customer can transfer generation to another meter(s) owned by the same entity (e.g. a council has space for solar PV at one site and demand for renewable energy at a nearby facility).
- A generator-customer can transfer or sell exported generation to another nearby site.
- Community-owned renewable energy generators can transfer generation to local community member shareholders.
- Community retailers can aggregate exported electricity generation from generator-customers within a local area and resell it to local customers.

1.3 The overall research project

The objective of the project is to create a level playing field for local generation by facilitating the introduction of Local Network Credits and Local Electricity Trading. The key outputs are:

a. improved stakeholder understanding of the concepts of Local Generation Network Credits and Local Electricity Trading

b. five ‘virtual trials’ of local network charges and Local Electricity Trading in New South Wales, Victoria, and Queensland, in which the impacts of both an LGNC and LET on specific projects are explored[9]

c. economic modelling of the benefits and impacts of Local Generation Network Credits

d. a recommended methodology for calculating Local Generation Network Credits

e. an assessment of the metering requirements and indicative costs for the introduction of Local Electricity Trading, and consideration of whether a second rule change proposal is required to facilitate its introduction

[9] Rutovitz, J., Langham, E., Teske, S., Atherton, A. & McIntosh, L. (2016) *Virtual trials of Local Network Charges and Local Electricity Trading: Summary Report*. Institute for Sustainable Futures, UTS

f. support for the rule change proposal for the introduction of a Local Generation Network Credit submitted by the City of Sydney, the Total Environment Centre, and the Property Council of Australia.

1.4 Structure of this report

An overview of the methodology is given in Section 2, including some of the key terms. Within this section we provide a description for the development of the representative agent model along with some of the key datasets used to parameterise and calibrate the model. This section also includes the calculation methods for the estimation of LRMC and LGNC values, and the structure of the model itself. Assumptions and limitations of the model are then discussed in detail in Section 3. Results are presented in Sections 4 and 5. More detail on the values used in the modelling are given in the Appendices A–F.

2 METHODOLOGY

The following section sets out the main approach that was used to estimate the economic costs and benefits of an LGNC compared to business as usual. In order to estimate the overall economic impacts of the LGNC it was important that the model was forward looking and was able to estimate the economic costs and benefits as demand and supply on the electricity network changed over time in response to changes to the profiles for different consumers and producers on the network. In order to accomplish this, we developed two primary scenarios for comparison: (i) a business as usual scenario and (ii) an LGNC payment scenario.

2.1 Terminology

Representative agent

In this model a 'representative agent' (sometimes called an agent) is a consumer, producer or prosumer on the electricity network that embodies a set of unique characteristics setting them apart from other agents in the model. Representative agents characterise the average behaviour of all consumers that belong to that agent category. It is therefore possible to multiply the annual consumption of the agent by the number of agents that belong to that category to calculate the aggregate characteristics of all consumers belonging to a particular representative agent type. The aggregate characteristics for different levels of the network can therefore be determined from the consumption (GWh), demand (MWpeak) and generation (GWh) of each representative agent type and the total number of agents belonging to each agent category.

Customer class

A customer class is a category to which similar representative agents belong. For example, in this model we have a residential customer class to which residential representative agents belong. Individual consumers within a representative agent category are able to switch to other representative agent categories within the same customer class (e.g. a consumer to prosumer switch).

Network expansion

Network expansion is the term used to describe future investment in network infrastructure. This investment includes capital expenditure (capex), operational expenditure (opex), replacement expenditure (repex) and connection expenditure (connex).

Gross generation

Gross generation is the total amount of electricity produced by a representative agent in the model measured in kWh.

Gross consumption

Gross consumption is the total consumption of an agent, typically over a year measured in kWh.

Net imports

Net imports is the electricity import consumption requirements of a representative agent or customer class from the network.

Net exports

Net exports is the electricity exported back to the network by representative agents. The equation for estimating net imports or net exports is based on half-hourly increments using the following equation

When Generation(t) < Consumption(t)

Net imports(t) = Consumption(t) – Generation(t)

Else Generation(t) > Consumption(t)

Net Exports(t) = Consumption(t) – Generation(t)

As shown in the equation above, Net Exports(t) and Net Imports(t) use the same equation but when Generation(t) > Consumption(t) the sign of electricity flow changes from positive to negative, thus electricity exports were treated as a negative quantity in this model.

2.2 Modelling approach

The overall aim of this modelling exercise was to estimate the overall economic costs and benefits at a macro level. However, this was not possible without first developing a model of consumption (and generation) at a micro level for different categories of consumers and producers (agents). A bespoke model was therefore developed for each representative agent, providing details on the overall peak demand, consumption, generation, net imports and net exports for that agent type. In summary, the following variables were estimated for each agent:

- demand profiles for three seasons and peak day
- generation profiles for three seasons and peak day
- peak demand on network (kW)
- annual total gross and net import consumption (kWh)
- annual peak period gross and net import consumption (kWh)
- annual shoulder period gross and net import consumption (kWh)
- annual off-peak period gross and net import consumption (kWh)
- annual total gross and net export generation (kWh)
- annual peak period gross and net export generation (kWh)
- annual shoulder period gross and net export generation (kWh)
- annual off-peak period gross and net export generation (kWh).

As each representative agent reflects the average of all customers within that category, it is possible to estimate the aggregate impact by multiplying the consumption of the representative agent by the total number of customers that belong to that representative agent category. This multi-level approach therefore provides a robust and transparent method for studying how the combined effects across all agent types would lead to increased demand (or contraction) on the electricity network over time.

This also provided the capability for estimating the impact of each agent on the electricity grid as the number of customers within each representative agent category changes over time. With data on the profiles of each agent, and information on the amount of electricity generated, consumed and exported to the grid at different times of the day, it was possible to scale the effects of each agent to understand their impact in aggregate on the network.

The complicated nature of this problem is self-evident given that future network expansion depends on the growth in the peak demand on the network. The coincident peak demand on the network depends on the aggregate of the demand of each of the different customers (agents) on the network. Different agents have different demand profiles, and as the number of consumers belonging to each representative agent category on the network expands or contracts this has an impact on the overall coincident peak load on the network.

Complicating matters further is that some agents can generate electricity and therefore they have the ability to export electricity back into the grid. Such agents are commonly referred to as prosumers. As coincident peak demand on the network is determined by summing the aggregate profiles across all representative agent categories, when the number of consumers within a category changes over time, it has an impact on both the time and magnitude of peak electricity demand on the network. Therefore, network peak demand does not necessarily have to coincide with the peak demand from any single representative agent. The magnitude of peak demand on the network is estimated in ten-year intervals and the average annual growth rate of peak demand is then calculated for each decadal period. These growth rates are then used to determine the average annual expected change in peak demand on the network overall.

2.3 Representative agent model

The model starts with the premise that aggregate electricity peak demand (MWh/h), consumption (MWh) and generation (MWh) within an electricity network can be approximated by modelling “representative agents”. By definition, a representative agent is a single entity that represents the average characteristics of all customers belonging to that category. For example, in NSW and the ACT the peak demand from residential consumers is 2.75 GWpeak with an annual demand of 14.18 TWh per year. As there are 3.19 million customers in this customer class, the average peak demand across all residential consumers is 0.86 kWhpeak and 4.45 MWh per year.

In a similar way, electricity demand profiles are created for each representative agent so that aggregation of all consumers within a representative agent category represents the impact of that agent category on the network as a whole. Similarly, summing across all representative agents and customer classes allows us to estimate the impact on the electricity network as whole at different distribution network levels (e.g. low voltage, high voltage and transmission).

Each agent within the model also belongs to a “customer class” which is defined as the parent category to which representative agents belong. For example, the customer class of ‘residential’ includes representative agents for ‘residential’, ‘residential + solar’ and ‘residential + solar + battery”. In Table 4, the column headers show the customer class while rows below each customer class category show the representative agents. Residual demand on the network that is not met by local generation represents a load on the transmission network and is therefore provided by some form of centralised generation.

Table 4: Customer classes and representative agents

Residential	Small Commercial	Large Commercial	Local generation
A_Residential	D_Commercial	G_Large Commercial	J_Wind Farm
B_Residential + Solar	E_Commercial + Solar	H_Large Commercial + Cogen	K_Solar Farm
C_Residential + Solar + Battery	F_Commercial + Solar + LGNC	I_Large Commercial + Cogen + LGNC	L_GenSet

Agents belonging to a customer class are assumed to have similar characteristics. For example, the *gross* annual electricity consumption (kWh) of all representative agents belonging to the residential customer class is the same. In later versions of the model, it will be possible to change the characteristics of each representative agent to account for increased efficiency and demand response, so long as the sum of all agents equals aggregate demand and aggregate generation on the network. In addition, the *initial demand profiles* for each agent within a customer class category are also the same. However, if an agent also produces its own electricity, this will change the net import demand profile for that agent. Therefore, the final net import electricity profile for each representative agent differs as each agent has different generation characteristics and they will change the electricity demand requirements on the network. Agents within a customer class differ in how much energy they generate behind the meter, and in when that energy can be exported to the grid. For example, a residential agent with PV will generate electricity during sunny periods of the day and only when that generation exceeds consumption for that time of the day will their electricity be exported to the grid. Electricity generation and the amounts that are consumed and exported to the grid are therefore a function of the demand requirements of that agent and their capacity to generate electricity at different times of the day.

The aggregate impact on the grid is the sum total demand requirements of all representative agents and customer class categories. A feature of the model is that it allows customers within a representative agent category to switch within a customer class to being another type of representative agent with a different set of characteristics. The proportion of representative agents within each customer class is therefore allowed to change over time, whilst maintaining the overall growth rate of each customer class category. In other words, representative agents can switch between representative agent types within a customer class but not across customer classes (e.g. a typical residential consumer can become a residential + solar). The aggregate impact on the network as a whole is the net impact of all representative agents on the network.

The overall characteristics of each representative agent are provided in Figure 3 where it can be seen that each representative agent has the ability to either (i) import electricity from the network; (ii) generate and consume their own electricity; (iii) export electricity to the grid; or, (iv) import, generate and export electricity to the network.

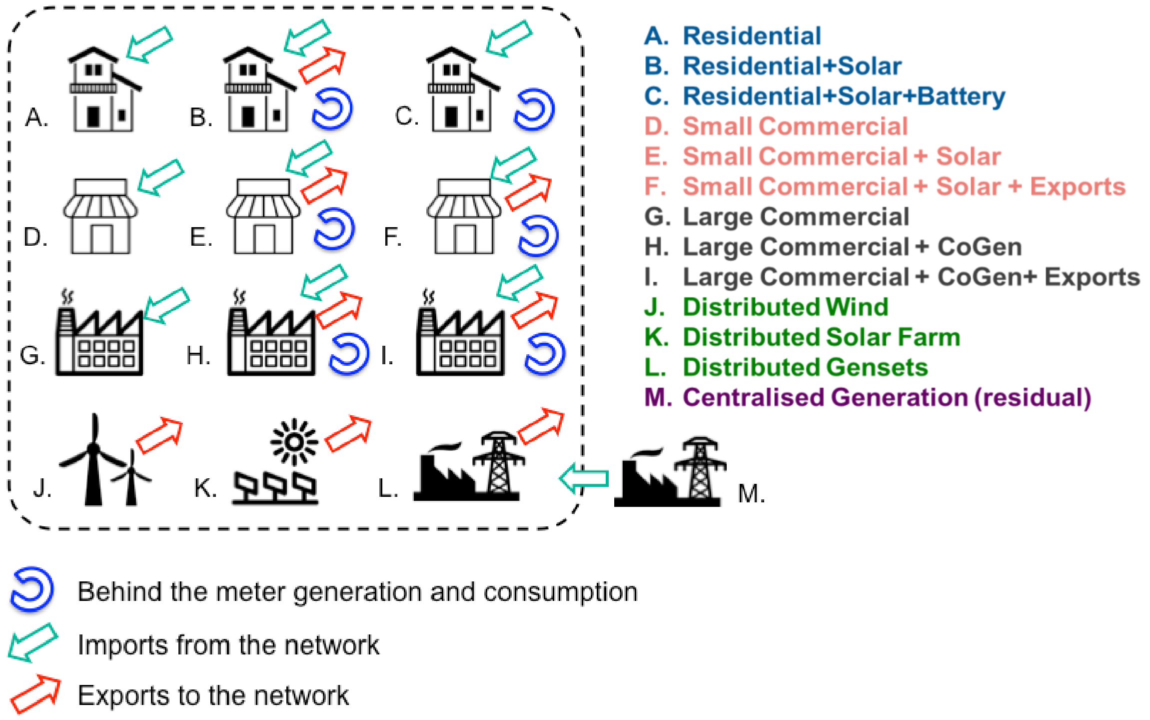


Figure 3: Representative agent characteristics

2.4 General data sources

The key datasets used in the construction and parameterisation of the model are listed in Table 5

Table 5: Data sources used in the model

Data source	Date	Description
AEMO National Electricity & Gas Forecasting http://forecasting.aemo.com.au/	2015 and 2016	This dataset provides both historical and forecast information on peak demand, annual consumption and distributed generation across different end-user categories for each state in Australia. In general the forecasts for underlying consumption have been taken from NEFR 2015, while the forecasts for distributed generation growth all come from NEFR 2016.
CSIRO Electricity Profiles http://doi.org/10.4225/08/5631B1DF6F1A0	2015	This database includes normalised average daily load profiles for residential, commercial and industrial customers. There are profiles for summer, winter and shoulder seasons.
Energy Supply Association of Australia (ESAA) Annual Reports http://www.esaa.com.au/	2015	This database includes statistical summaries of published figures taken from energy market participants. Statistics include the number of customers and annual, consumption and peak demand by customer class. It also includes figures for PV installations by capacity and generation.
Department of Industry and Science – Australian Energy Statistics http://www.industry.gov.au/Office-of-the-Chief-Economist/Publications/Pages/Australian-energy-statistics.aspx	2015	This database includes energy balance statistics on electricity supply and generation by state.
Australian PV Institute www.apvi.org.au	2015	This database includes postcode data on the capacity and generation of solar PV
Clean Energy Regulator (RET) http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations#SGU--Wind-Deemed	2015	Provides information on the number of small-scale generators by state for solar, wind and hydro.
NEM-Review Database	2015	This database is a comprehensive software application that includes a

Data source	Date	Description
http://v6.nem-review.info/use/enjoy/data/datasets/datasets.aspx		large variety of energy related statistics.

2.5 Initial conditions

The initial conditions are taken from existing reputable data sources and are used to parameterise the model. Many different sources of information and data were used to determine the initial conditions on which the model is based (see Table 5). The number of customers that belong to each customer class category (e.g. residential, commercial and large commercial) are taken from ESAA annual reports. Annual consumption and peak consumption by customer class are taken from AEMO historical data and forecast reports. Combining these datasets, we estimate annual average consumption and average peak consumption for an average representative customer. The total number of agents, gross consumption, net import consumption (from grid), gross generation and net export generation (to the grid) are shown in Table 6.

Table 6: Agent level consumption and generation statistics

	No. Agents[1]	Gross consumption per agent[2]	Net import consumption per agent[3]	Gross generation per agent[4]	Net export generation per agent[5]
	2015	kWh / year	kWh / year	kWh / year	kWh / year
A - Residential	2,849,461	4,447	4,450	-	-
B - Residential with PV	339,633	4,447	2,911	3,641	2,102
C - Residential with PV + Battery	100	4,447	919	3,641	-
D - Small Commercial	397,954	92,290	92,290	-	-
E - Small Commercial with PV	9,276	92,290	63,107	29,183	-
F - Small Commercial with PV + export	100	92,290	53,206	42,921	3,837
G - Large Commercial	49,347	296,780	296,780	-	-
H - Large Commercial with cogen	105	1,666,667	719,256	1,000,772	53,362
I - Large Commercial with cogen + export	10	1,666,667	546,403	1,215,902	95,638

1. Numbers of agents are from ESAA annual report 2015
2. Gross consumption per agent is calculated by dividing total consumption by the number of agents in each category
3. Net import consumption is estimated from the net energy profiles where half-hourly demand is greater than own generation
4. Gross generation is calculated from solar generation data from APVI data and the number of installations
5. Net export generation is estimated from net energy profiles where half-hourly generation is greater than demand.

Aggregate gross consumption and aggregate net import consumption across all customers belonging to each representative agent type are given in

Table 7.

Table 7: Aggregate gross consumption and net import consumption[1]

Representative agent type	2015 Gross Consumption GWh / year	2030 Gross Consumption GWh / year	2015 Net Import Consumption GWh / year	2030 (BAU) Net Import Consumption GWh / year
A - Residential	12,681	12,710	12,681	12,710
B - Residential + PV	1,512	2,509	989	1,641
C - Residential + PV + Battery	0	1,505	0	311
Total Residential	14,193	16,724	13,670	14,662
D - Small Commercial	36,727	39,634	36,727	39,634
E - Small Commercial + PV	856	4,651	585	3,180
F - Small Commercial + exports Exports	9	9	5	5
Total Small Commercial	37,592	44,296	37,318	42,820
G - Large Commercial	14,645	15,699	14,645	15,699
H - Large Commercial + cogen	174	275	75	119
I - Large Comm + cogen + exports	16	18	5	6
Total Large Commercial	14,836	15,992	14,726	15,823
Total Demand	**66,622**	**77,011**	**65,716**	**73,307**

1. Aggregate gross consumption and aggregate net import consumption (network demand) are calculated by summing totals across all agent types. Total generation and consumption data are from AEMO forecasts and customer numbers are from ESAA data.

Aggregate gross and net export generation across all customers belonging to each representative agent type are given in Table 8 for 2015.

Table 8: Aggregate gross and net export generation

Representative agent type	2015 Gross Generation GWh	2030 Gross Generation GWh	2015 Net Export Generation GWh	2030 (BAU) Net Export Generation GWh
A - Residential	-	-	-	-
B - Residential + PV	1,219	2,023	714	1,185
C - Residential + PV + Battery	0	1,214	-	-
Total Residential	1,219	3,237	714	1,185
D - Small Commercial	-	-	-	-
E - Small Commercial + PV	267	1,450	-	-
F - Small Commercial + Exports	4	4	-	-
Total Small Commercial Customers	271	1,454	-	-
G - Large Commercial	-	-	-	-
H - Large Commercial + cogen	105	165	6	9
I - Large Commercial + cogen + exports	12	13	1	1
Total Large Commercial	117	178	7	10
J - Wind Power	28	45	28	45
K - Solar Farm	31	48	31	48
L - GenSet	370	584	370	584
Total Local Generation	428	677	428	677
Total Generation	**2,036**	**5,547**	**1,149**	**1,872**

Data on the number of PV installations, annual generation and total PV capacity are taken from APVI statistics available online.[10] With this information we estimate the average PV

[10] http://pv-map.apvi.org.au/

generation and average installed PV capacity by customer class (residential and small commercial). The initial conditions are found below in Table 9. Electricity generation from cogen plants is estimated from known AEMO distributed generation units operating behind the meter.

Table 9: Solar PV statistics for NSW and ACT (2015)

2015	Count #	Total Installed Capacity MW	Average Installed Capacity kW	Total Annual Generation GWh	Average annual Generation MWh
Residential (<10kW)	339,633	893	2.63	1,237	3.64
Commercial (>10kW)	9,276	186	20.07	271	29.18

1. Total number of premises, capacity and total annual generation was taken is from APVI data.

Existing data on local generation for NSW indicates that total distributed generation amounts to approximately 2.28 TWh per annum with approximately 1.318 TWh being exported to the grid. Around 1.5 TWh of gross generation is from solar PV, representing about 66% of local generation. However, most of this generation is behind the meter. Our modelling suggests the amount of electricity actually exported to the grid from roof solar PV amounts to approximately 714 GWh or 52% of total exports. Table 31 in Appendix A gives the starting conditions for gross generation and net exports in 2015.

2.6 Projections for underlying growth

Projections in gross consumption were taken from AEMO forecast reports[11] and are shown in Table 10. Projections of gross consumption are the same for both BAU and LGNC. However, projections by representative agents within customer classes differ by scenario. Aggregate gross consumption remains the same in both scenarios but net import consumption from the grid differs by scenario as the LGNC scenario has a greater uptake of local energy and therefore a higher amount of behind-the-meter consumption and a higher level of export generation to the distribution network. For details on the growth by representative agent see Appendix D.

Table 10: Projections by customer class

Customer class	*2015-2020*	*2020-2030*	*2030-2040*	*2040-2050*	Average Annual Growth
Total residential customers	0.90%	1.20%	1.20%	1.00%	1.10%
Total small commercial customers	0.90%	1.20%	1.20%	1.00%	1.10%
Total large commercial customers	0.50%	0.50%	0.50%	0.50%	0.50%

[11] AEMO 2015 National Electricity Forecasting Report http://forecasting.aemo.com.au/

2.7 Projections for rooftop solar and solar plus batteries

Projections for generation from residential PV, PV with batteries, and small commercial PV are derived from the AEMO NEFR 2016 neutral forecast for residential and business rooftop PV[12], and they are shown in Table 11. The projections for the residential sector are identical for the BAU and LGNC scenarios, as no LGNC is given to small systems in the modelled case, so there is no incentive for increased installations. There is additional growth in the commercial sector. Details of agent growth by scenario are given in Appendix D.

Table 11: BAU projections for rooftop PV

	2015 GWh	2020 GWh	2030 GWh	2040 GWh	2050 GWh
Residential PV	1,079	1,475	2,210	3,152	3,727
Residential PV with batteries	0	257	1279	2395	3,727
Small commercial	156	630	1,959	2,957	3,974
Total	**1234**	**2,362**	**5,448**	**8,504**	**11,429**

2.8 Stand-alone generation: initial conditions and projections

Care was taken to estimate the capacity and generation of stand-alone generation connected to the electricity network at the distribution level by representative agent type. The relevant agents are: large commercial with cogeneration, stand-alone solar, stand-alone wind, and stand-alone other.

Current and forecast generation by representative agent was calculated from the AEMO forecasts for small non-scheduled generation[13] and the AEMO list of generators[14], using assumptions on capacity factor and some additional data for specific generators. Only distributed generation with a nameplate capacity under 30MW is assumed to be connected below the transmission level.

Data on the amount of commercial scale cogeneration was calculated from AEMO existing non-scheduled generation statistics after other non-scheduled generation had been removed

We estimate the total capacity of solar farms in NSW is 234 MW with a total of 20MW connected to distribution networks, and annual generation of 30.5 TWh using an assumed capacity factor of 17%. There is 900 GWh per year of wind energy generated within NSW with 15.3 GWh produced below the transmission level. In total we estimate that local generation (excluding rooftop PV) accounts for less than 3.0% of total electricity generation in NSW.

Appendix A, and in particular in Table 28 and Table 30, give details on the generation per agent, and the derivation where relevant.

---

[12] Capacity values for residential PV with batteries are taken from: Australian Energy Market Operator (AEMO) (2015) Emerging Technologies Information Paper, with the generation calculated using a capacity factor of 15.8% (APVI capacity factor for NSW)

[13] http://forecasting.aemo.com.au/Electricity/AnnualConsumption/SmallNonScheduledGeneration

[14] AEMO 2016 National Electricity Forecasting Report www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information

Table 12 shows the projected growth rate for generation (GWh) exported by stand-alone generation type for the BAU scenario. The growth rate is averaged over the entire period.

Table 12: Projections of stand-alone distributed energy

BAU Scenario	*2015-2020*	*2020-2030*	*2030-2040*	*2040-2050*
Wind Power	3.1%	3.1%	3.1%	3.1%
Solar Farms	3.1%	3.1%	3.1%	3.1%
Other (wood, biogas, diesel)	3.1%	3.1%	3.1%	3.1%
LGNC Scenario				
Wind Power	4.7%	4.7%	4.7%	4.7%
Solar Farms	4.7%	4.7%	4.7%	4.7%
Other (wood, biogas, diesel)	4.7%	4.7%	4.7%	4.7%

2.9 LRMC and LGNC estimates

The outputs of the economic model rely on estimates of the long run marginal cost (LRMC) of network expansion and the price of Local Generation Network Credits (LGNC). Energeia was commissioned by ISF to calculate LRMC values for five networks, using publicly available information, as part of the overall project *Facilitating local network charges and virtual net metering*. These LRMC values are used in the economic modelling in preference to the LRMCs given by the networks themselves, in order to allow for consistency of Repex inclusion, and to allow for testing whether this inclusion makes a significant difference. These LRMC values were also used for the calculation of consistent LGNC values.

Estimating LRMC values

The cost of future network expansion is a direct function of the increase in peak demand. These are calculated using LRMC values estimated by Energeia[15] (see Appendix B). Energeia used the average incremental cost (AIC) method for estimating LRMC values for several Australian DNSPs.

The equation for estimating LRMC using this method is shown below (Equation 1):

$$AIC = \frac{NPV(Augex+Opex+Repex+Connex)}{NPV(\Delta\, Peak\ Demand)} \tag{1}$$

Demand-related investment in capital expenditure is the sum of augmentation (augex) expenditure (e.g. new infrastructure), replacement expenditure (repex), and connection expenditure (connex). The estimates assume a capital recovery factor based on the real weighted average cost of capital (WACC) and a configurable average asset lifetime, initially set at 40 years.

Incremental operations and maintenance (Opex) are calculated as configurable percentages of the incremental capital expenditure. Growth-related replacement expenditure enters the model as a percentage of the overall replacement expenditure initially set at 2.5%.[16] Repex is defined as the annual incremental repex capital expenditure associated with asset replacement driven by the economic condition of the asset. Repex expenditure does not take into account the upgrade of infrastructure above modern equivalents. Two types of repex are

[15] Energeia 2016. AIC Calculator

[16] Replacement expenditure can account for up to 70% of total network investments in any given year.

included in the AIC calculation – first, repex on existing assets and secondly repex on future augmentation assets. Repex on existing assets is not typically associated with demand growth, however, modern equivalent replacement assets have higher capacity than those they replace. The assumption is therefore made that there is an annual incremental repex cost associated with expanding the network equivalent to a configurable 2.5% of total repex.[17] The proportion of repex expenditure on the overall LRMC value is estimated to be around 1%.

The incremental network demand is the year-on-year increase in peak kVA on the network. The LRMC calculated by Energeia defines incremental demand as the additional coincident weather-adjusted electricity peak demand measured at the meter in MVA that must be supported by the network each year. It excludes network losses and is a function of the number of customer connections, the average customer peak demand and the extent to which the peaks in customer demand coincide with the peaks in network demand. For an overview of Energeia's estimates of the LRMC values see Appendix A.

The NPV calculations were estimated in real terms, using the real WACC as per the Australian Energy Regulator (AER). This value differs by DNSP. LRMC values are calculated for low voltage (LV), high voltage (HV), sub-transmission (ST) and transmission (TR).

A comprehensive description of the methodology is given in the LRMC methodology paper.[18]

Estimating LGNC values

The values of LGNC tariffs (payments) are calculated from the LRMC values provided by Energeia. When the LGNC is calculated for a particular connection level, only the network levels above that level are included in the LGNC payment. We corrected for power factor (to convert from kVA to kW) and loss factor (to account for electricity losses as power is transmitted and distributed). Power factors and loss factors were provided by the DNSPs. Transmission LRMC values were also estimated and adjusted for power factor and loss factor from publicly available data. The combination of the above calculations gave us the total annual value of the network upstream of the generator in $/kWpeak broken down by voltage level.

The LGNC tariff is intended to provide a price signal to generators about when to generate and export electricity. While two different tariff-setting methods were used in the virtual trials undertaken in this project, only the volumetric method is used for the economic modelling, due to the additional complexity of applying a capacity payment. This, however, should be the subject of further research as a straight volumetric payment does not account for the locational basis of generators as payments are smeared across all generators.

LGNC methodology

To get the kWh value of the LRMC, we divided the annual kW value by 8,760 (total hours in the year). Each hour was weighted according to its value to the network (i.e. according to the probability of network load peaking within that hour). For example, one network advised that the peak was 90% likely to occur during a peak period, and peak periods accounted for 600 hours of the year. The total value for each network level was then split according to this probability to assign a value to each hour:

[17] 2.5% is the number recommended by Energeia as representing the growth in repex avoiding future augmentation expenditure.
[18] Energeia. 2016. LRMC methodology paper. Prepared for the Institute for Sustainable Futures.

During peak hours the tariff would be:

$$LGNC\ \$/kWh = \frac{LRMC\ for\ network\ levels\ above\ connection\ x\ 90\%}{600}$$

During off peak hours the tariff would be:

$$LGNC\ \$/kWh = \frac{LRMC\ for\ network\ levels\ above\ connection\ x\ 10\%}{8760}$$

Thus in order to calculate the LGNC the following variables are required:

- LRMC per network level
- peak, shoulder and off-peak times
- probability of the peak occurring in each period (peak, shoulder and off-peak).

The LGNC values were calculated using the LRMC values supplied by Energeia, with the other variables (peak times, probability of peak occurring) set at the values given by Essential Energy and Ausgrid during the virtual trials. The values of the LGNC tariffs and the peak times and probabilities are given in Appendix B.

The model includes the ability to apply a "benefit share" multiplier to the calculated LGNC value, whereby only a proportion of the value is given to the generator. In this modelling the benefit share was set to 80%, meaning 80% of the LGNC calculated value is given to the generators, the remaining benefit goes to the network provider.

2.10 Structure of the model

Figure 4 shows the overall structure of the representative agent model. On the far left of this diagram are the main inputs of the model. These inputs include both actual data from reputable publicly available sources and user defined input assumptions that can be modified for each scenario.

The following list is a summary of the calculation procedures completed by the model:

1. Initial conditions are taken from existing publicly available data sources as listed in Table 5.
2. Representative agent profiles are estimated to meet aggregate consumption and peak demand requirements. Gross consumption, gross generation net import consumption and peak demand requirements are estimated for each agent from their underlying profiles.
3. Initial conditions and user input data are used on the main tab to estimate annual growth rates in each customer class category and the number of agents that belong to each representative agent category.
4. These growth rates are then used to estimate aggregate annual impacts for each representative agent.
5. Gross annual generation is the total generation from each representative agent across the network and includes generation that is also consumed behind the meter.
6. Gross annual consumption is total annual consumption for each representative agent and includes consumption behind the meter and demand from the network.

7. Net annual imports are import requirements from the distribution network for each representative agent to satisfy their demand in each period estimated on a half-hourly basis for peak, shoulder and off-peak periods over the day.
8. Net annual exports are the exports generated by distributed energy and exported to the distribution network for each period (peak, shoulder, off-peak).
9. Peak day profile analysis estimates the aggregate peak demand on the network across all representative agents in 10-year increments given the input growth assumptions entered by the user. The time at which aggregate coincident peak occurs on the network is then calculated.
10. Peak demand requirements for LV, HV and TR levels of the network are estimated.
11. LRMC values in $/kVA/year are used to estimate the annual incremental cost of network expansion from growth in network peak demand.
12. LGNC values ($/kWh/year) are used to estimate agent level exports to the grid in off-peak, shoulder and peak periods as defined by network operators.
13. The net present value of costs in each scenario are then calculated and compared.
14. The impact on customer bills is estimated assuming that future network costs and benefits for both LRMC and LGNC payments are allocated proportional to annual consumption.

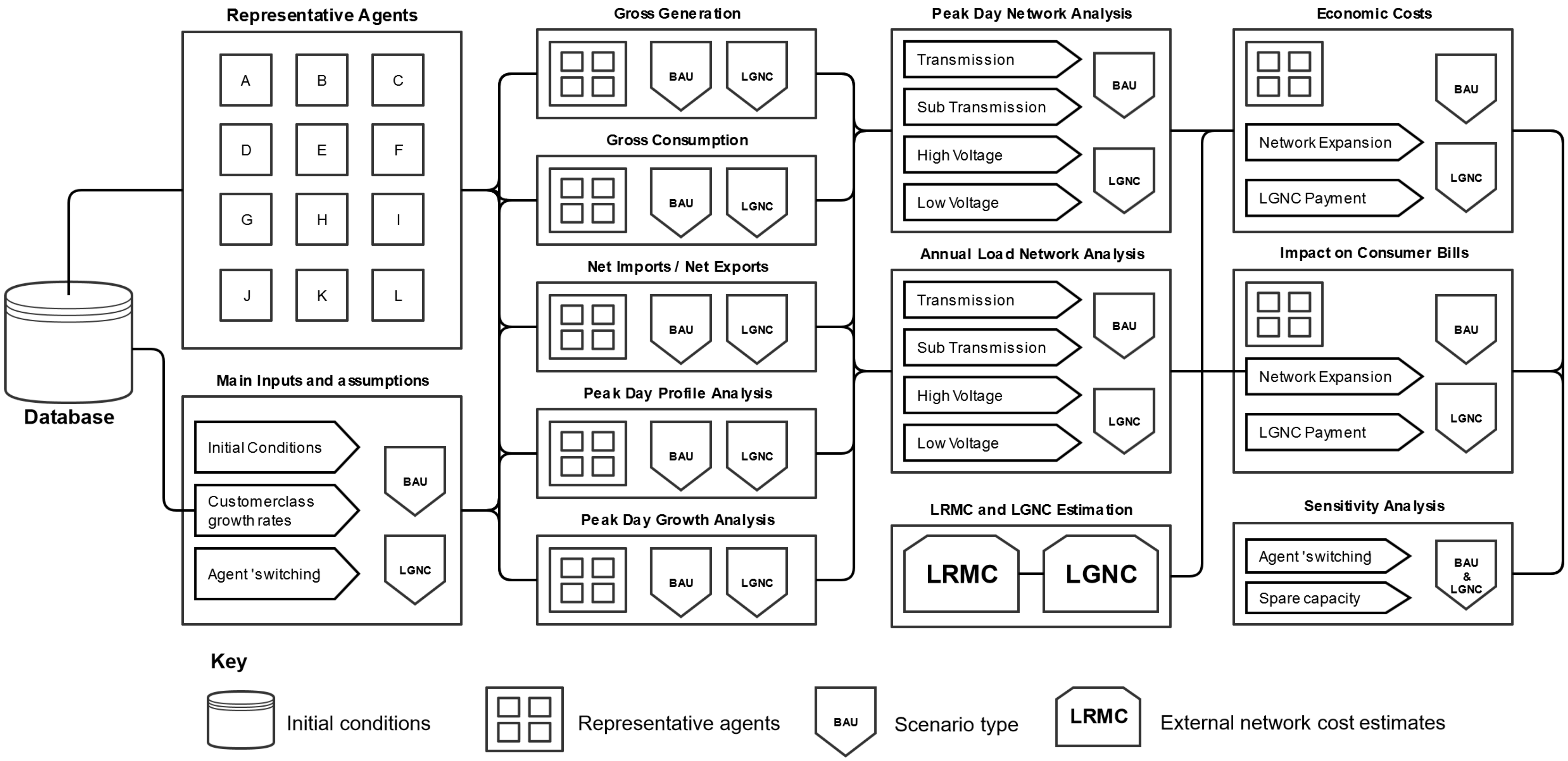


Figure 4: Structure of representative agent model

Representative agent worksheets

Within the model each representative agent has its own worksheet. These are diagrammatically represented in the first block in the left Figure 4 titled 'representative agents' and shown by the letters A–L. Each of the twelve representative agents is configurable to match the requirements of the agent type. Daily demand profiles are included for three seasons of the year, namely, summer, winter and autumn-spring. These profiles represent the average typical coincident demand profiles for each agent type on the network for that season. The total gross consumption for an agent over any particular season is calculated as the total daily consumption for that season multiplied by the total number of days in that season. Similarly, annual consumption is just the sum of total consumption across all seasons. A peak-day profile is also included to represent the profile of a representative agent on a peak day. This peak-day profile from all agents is used to estimate the coincident peak demand across the entire electricity network for all agent types in each year. Thus, the coincident peak on the network is not necessarily the coincident peak of each representative agent but the coincident peak demand on the network across all agent types.

An optimisation algorithm was used to estimate coincident daily demand profiles for each agent consistent with the aggregate annual consumption (MWh) and aggregate annual peak demand (MWpeak) for that agent type. This optimisation algorithm was used to estimate the demand requirements at half-hourly intervals whilst satisfying the model constraints. First, normalised demand profiles were created for each agent type where the peak demand for each profile was set as equal to one. Each seasonal demand profile was then set as equal to some ratio of the summer profile based on historical estimates. For areas where winter is established as the peak profile, this ratio can be set at greater than one to match the peak demand requirements from that agent. The optimisation model that was used to perform this calculation took the following form:

set: $\widehat{x_{t,s}} = f\left(\beta x_{t,s} + {x_{t,s}}^{\gamma}\right)$

subject to the constraints: $\sum \widehat{x_{t,s}} = C_g$ where $C_g > 0$

and $max\ \hat{x}_t = C_p$ where $C_p > 0$

subject to: $\alpha \in (-5, 10)$; $\gamma \in (0,2)$

From these equations $x_{t,s}$ represents the normalised demand profile for an agent at time t, for season, s, while $\widehat{x_{t,s}}$ represents the new demand at time t that satisfies the constraints of aggregate annual gross consumption, C_g, and aggregate peak demand C_p on the distribution network for that agent type. The constants β and γ are found by the optimisation algorithm and represent the scaling factors on demand at time t. The parameter β represents a straightforward multiplication scaling factor, while the parameter γ represents a power scaling factor. The parameter γ has the property of making a profile more or less peaky to meet the specified constraints of peak demand and annual consumption for the average representative agent on the network. An illustration for a selection of the different agent profiles is shown in Appendix F.

The main inputs tab

The main inputs and assumptions tab (lower left Figure 4) is the primary user interface for altering model input assumptions. The main tab allows input conditions for two scenarios: i) BAU and ii) LGNC. Growth rates for each customer class category, and the initial conditions for different representative agents, are set here and may be changed, as can the proportion of agents that belong to each representative agent category. However, the BAU scenario has been parameterised based on best available knowledge and published projections. The proportion of agents that belong to each category are stipulated in blocks of ten years starting in 2020. The model then calculates the required annual growth rate requirements to meet user-defined input conditions. These growth rates are then used by the rest of the model to estimate the system-wide impacts of each agent type on the network.

Other parameters on the main tab that can be modified by the user include:

- the distribution network parameters being used in the model (Ausgrid or Essential). This changes the peak, shoulder and off-peak billing periods and rates used for the LGNC
- the number of days in each season
- power factor correction values for each level of network
- discount rates
- the period over which loans are repaid
- the inclusion of existing non-dispatchable generation in LGNC payments
- the inclusion of existing dispatchable generation in LGNC payments
- the estimated amount of spare capacity on each of the three network levels and by extension the year at which investment in the network needs to be made
- the level of network benefit (avoided augmentation) accruing to the level where the distributed generation is installed (initially set at 50% though this effect is minimal)
- whether LGNC should be paid on systems under 10kW capacity.

In addition, the user has full control to adjust underlying growth rates in customer class categories, or representative agent categories. They can also adjust growth rates in the uptake of stand-alone generation.

3 ASSUMPTIONS AND LIMITATIONS

In order to capture the complexity of this process but still make such a model tractable, we needed to make a number of simplifying assumptions whilst maintaining the overall integrity of the model to answer robustly the research questions. As with all models, the outputs are a function of the initial conditions, the input parameters and the assumptions that are made when constructing the model.

3.1 Representative agents

One of the key assumptions is that aggregate peak demand and aggregate consumption on the network can be estimated by representative agents on the network. As already discussed, agents can be consumers, producers or prosumers. In this version of the model the characteristics of the agent are fixed (i.e. average consumption and generation does not change over time) but the number of consumers belonging to each representative agent category is allowed to vary, which ultimately impacts aggregate demand. Because of this assumption aggregate demand on the network varies according to the following characteristics of each representative agent:

- the underlying growth in demand from each customer class
- the total number of agents that belong to each customer class and representative agent category in each year
- the energy profiles of the agents in the model, and by extension, the annual consumption and peak demand requirements of that agent on the network
- the rate at which agents switch within a customer class and adopt the characteristics of another type of representative agent (e.g. a residential consumer installing PV).

3.2 Initial conditions and the use of DNSPS

The initial conditions of the model are also important for establishing the rate of growth of the number of consumers within each representative agent category. This version of the model has been parameterised using statistical data for NSW. Thus, the conclusions from this analysis only extend to the state of NSW. Diversity within NSW and between DNSPs was brought in by including individual data for Ausgrid and Essential Energy. For example, separate LRMC and LGNC values were used for each DNSP. In addition, peak billing periods were also modified depending on the peak billing periods of the DNSP being modelled. The overall effect for NSW was then found as the weighted sum of results from Ausgrid and Essential Energy.

It is important to note that even though an individual DNSP is selected, the numbers that are being estimated (e.g. economic costs) are for the state as a whole as the underlying number of consumers and other statistical data are for the entire state. The correct way to interpret these conclusions is that the results represent the effects for the entire state. Future versions of this model will overcome this limitation by entering initial conditions (e.g. number of agents, consumption and generation) for each DNSP where the sum of the DNSPs operating within a state would give results for the state as a whole.

3.3 User inputs

The model is parameterised using both existing data on the consumption and generation profiles for NSW and user-provided inputs. In both scenarios, the rate of growth in the number of consumers belonging to each representative agent category is provided by user-defined values. The underlying growth rate for the number of agents in each customer class is the same in both scenarios, so the effects of an LGNC payment can be compared against similar growth profiles. The business as usual scenario reflects a best guess estimate of the growth in consumer numbers in each representative agent category, which itself is a function of economic growth and population growth. Initial estimates of the underlying growth rates were based on data provided by AEMO and BREE. The second scenario requires user inputs for how an LGNC may change the adoption rates of distributed energy over time. Table 13 shows the relative fractions of agents that belong to each category for each scenario.

Table 13: Fraction of consumers within each representative agent category

Representative agent	BAU		LGNC Scenario	
	2020	2050	2020	2050
A - Residential	89.3%	56.0%	89.3%	56.0%
B - Residential + PV	10.6%	22.0%	10.6%	22.0%
C - Residential + PV + Battery	0.0%	22.0%	0.0%	22.0%
	100.0%	**100.0%**	**100.0%**	**100.0%**
D - Small Commercial	97.7%	78.0%	97.7%	60.0%
E - Small Commercial + PV	2.3%	22.0%	2.3%	22.0%
F - Small Commercial + LGNC	0.0%	0.0%	0.0%	18.0%
	100.0%	**100.0%**	**100.0%**	**100.0%**
G - Large Commercial	98.7%	97.0%	99.5%	79.1%
H - Large Commercial + cogen	1.2%	2.9%	1.2%	2.9%
I - Large Commercial + cogen + LGNC	0.1%	0.1%	0.1%	18.0%
	100.0%	**100.0%**	**100.0%**	**100.0%**

It should be noted that the modelled growth for residential plus PV and residential plus PV plus battery are the same in both the BAU and the LGNC scenarios. The residential plus PV scenario does not change in the modelled case as we have assumed an LGNC which is not paid to systems smaller than 10 kW. Thus, there is no incentive for additional PV in the LGNC scenario above the BAU scenario. This limit excludes all residential systems in our model. In the cases where we included payments to all local generators, residential plus PV expanded in the LGNC scenario.

There may well be an impact on battery plus PV penetration, and on discharge strategies, for both residential and commercial systems. However, it was beyond the scope of this work to research that interaction, so inclusion of that effect has been left for further developments of the model.

3.4 Electricity profiles and billing periods

The model includes half-hourly data over a 24-hour period for four representative profiles in the year (e.g. summer, winter, autumn-spring and peak-day). Each profile approximates the average daily profile for that season for that agent type. Using these profiles, consumption generation and net imports and exports from the grid are calculated for off-peak, shoulder and peak periods matching the billing periods for the DNSP being studied. It was necessary to estimate consumption and generation over these periods because flexibility was required for calculating tariffs and credits on a volumetric basis for determining peak demand on the network.

The model also includes profiles for solar generation. We estimate average solar profiles for three seasons and peak day (e.g. summer, winter, autumn-spring and peak-day). These profiles do not take into account the intermittency of solar in a probabilistic way and this represents an avenue for further research. For estimating the impact of solar PV on peak demand, the average summer PV profile is used.

3.5 The entry point of different agents on the electricity network

Each representative agent enters the network at a different level. Residential and small commercial consumers enter on the low voltage network, large commercial consumers enter at the high voltage level and stand-alone distributed generation enters at the sub-transmission level. In future versions of the model it will be possible to change the entry point of different agents on the network or change the proportion of agents within each customer class to enter at multiple points on the network. The entry point of each customer class is important because it leads to cascading impacts up the electricity network hierarchy, and has an impact on all higher levels on the network. For example, behind-the-meter consumption for residential consumers on the LV network will not only reduce peak demand on the LV network but will also decrease peak demand on the HV network and all networks above this level.

Table 14: Customer class entry on electricity network

	Low Voltage (LV)	High Voltage (HV)	Sub Transmission (ST)
Customer Class	Residential	Large Commercial	Stand-alone generation
	Small Commercial		

3.6 Treatment of exported electricity

Electricity exports into the grid from local generation are assumed to only impact the network above the level where they are exported. We assume that 50% of the benefit of exported electricity has an impact where it is connected, whereas the 100% of exports reduce demand at all upper levels. This method approximates the fact that there may be six network levels with agents connected at different points on the network, whereas we are only modelling three.

Actual effects are difficult to calculate accurately without knowing the exact load requirements on different parts of an LV network to create a detailed model of electricity flows and the probability of this leading to a reduction in load for that part of the network. In this model, we treat all LV zones within NSW as a single zone but it must be recognised that generation in one LV zone will not reduce demand in another LV zone located elsewhere. This model therefore captures the average increase across all zones. It is likely that some LV zones on the network will be more constrained than others, with demands being met by generators in close proximity, thereby reducing load from a feeder. However, it is also possible that generation at one part of an LV zone is only matched by demand on the other side of that LV zone (or not at all) thus not leading to any reductions in that LV zone. In the absence of further information, our assumption that load reduction only occurs at higher levels on the network avoids this complexity.

Estimating more accurately the proportion of generation that leads to load reduction across LV zones treated in aggregate is a matter for further modelling. Our hypothesis is that the network load savings as a proportion of overall exported generation are less for lower levels of the network and greater for higher levels of the network (e.g. electricity exported at the LV level may lead to reductions in future network expansion above the LV level).

3.7 Impact on customer bills

The impact on customer bills was estimated on a reflective basis. Each customer class has a different impact on the grid depending on the level at which they are connected to the grid and how much distributed energy enters the grid at points above them on them network. Augex, opex and repex costs also vary by network level. As network expansion costs vary and the impact of each customer class on each level of the grid varies, it is necessary to estimate the cost reflective impact that each customer class has at each level of the network. For example, residential consumers may be predicted to increase peak demand on the LV network by 100kVA. If no additional distributed energy enters the network at this level, this will cause a cascade of increases from the LV level to the TR level of 100kVA (+ losses) in transporting this electricity. If distributed energy were to meet, say 20kVA of this demand on the HV level, then the impact on the transmission level would only be 80kVA (e.g. a reduction of 20kVA (+ losses). Under these assumptions, residential consumers have caused an increase of 100kVA on the LV and HV network, and 80kVA (+ losses) on the TR network. The attribution of the costs of expansion on each network level was done by allocating costs to consumers based on their annual consumption. Therefore, the costs allocated to each customer class reflects the weighted contribution of each representative agent to the costs of network expansion. It was decided to use volumetric allocation rather than each representative agent's contribution to peak demand, as this more accurately reflects how electricity retailers presently charge for electricity consumption. Although we acknowledge it is peak consumption that drives augmentation, the charge for this augmentation occurs through volumetric and fixed payments irrespective of a consumer's contribution to peak demand.

3.8 Other limitations

- The model does not estimate the distributional effects of these savings across different income groups.
- The model does not estimate the effect on overall carbon emissions.
- The model does not include system losses associated with the transmission and distribution of electricity from upper levels to lower levels. These calculations were completed separately and are included for information in the results section.
- The benefits deriving from avoided losses were excluded because, for this analysis, we were only interested in including those costs associated with avoided network expenditure.
- We do not include the costs of augmenting distribution networks with additional technology to handle increases in local generation.

4 PEAK DEMAND AND GENERATION OUTPUT

4.1 Gross generation by representative agent type

Gross generation is the total local generation produced by each representative agent and includes generation consumed behind the meter and electricity exported to the grid. Small-scale non-scheduled generation presently accounts for 2.93% of total network-supplied electricity in NSW. Local generation is thus starting from a very low base. The graphs in Figure 5 show the growth in local generation in GWh/annum for each scenario that was modelled. As shown, locally produced gross generation increases to 12.74 TWh per annum by 2050 in BAU, and to 20.44 TWh per annum in 2050 in the LGNC scenario. BAU estimates are based on AEMO projections (http://forecasting.aemo.com.au/).

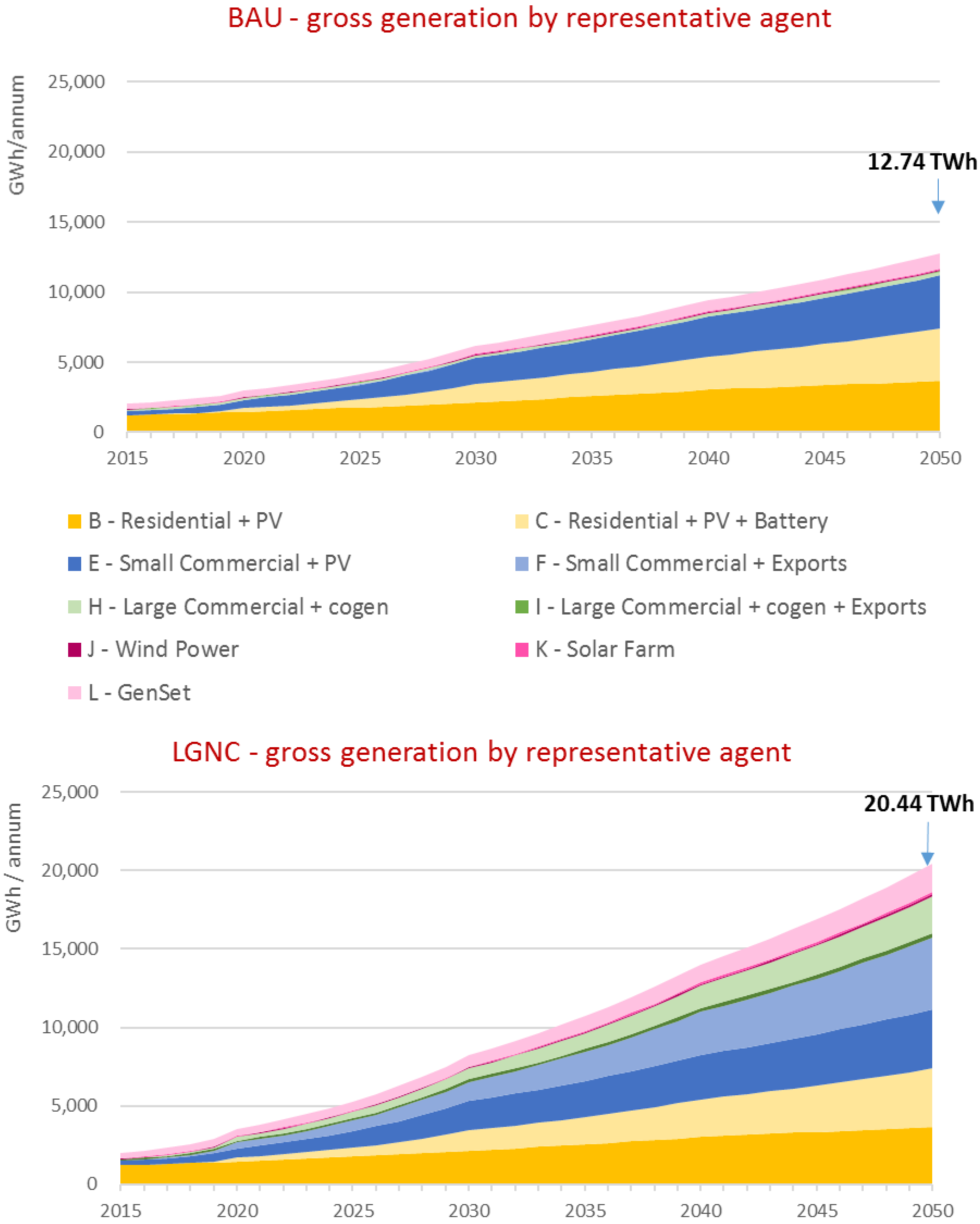
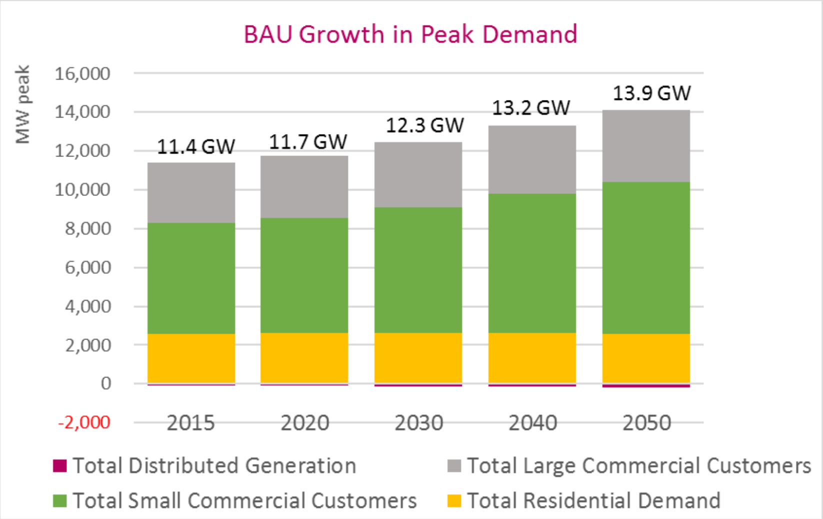


Figure 5: Gross generation by customer type, BAU and LGNC scenarios

Total gross consumption, including both self-generation and imports from the network, increases from 67 TWh in 2015 to 94 TWh in 2050 in both scenarios. Total consumption in 2050 remains constant between the two scenarios, although the mix by customer class changes somewhat as the new customer classes exist in the LGNC scenario. Imports and exports are significantly different by scenario, as would be expected, with much higher exports from local generation in the LGNC scenario. Grid imports are lower in the LGNC scenario because of the higher rates of self-generation and behind-the-meter consumption. Details of gross consumption, imports and exports are shown in Appendix E.

4.2 Peak demand

The electricity network is sized based on the expected growth in coincident peak demand on the network. Under the assumptions presented in this report, we expect peak demand on the grid to be overall 11.5% below business as usual projections by 2050 under the LGNC scenario as indicated in the figures below and in Figure 6.



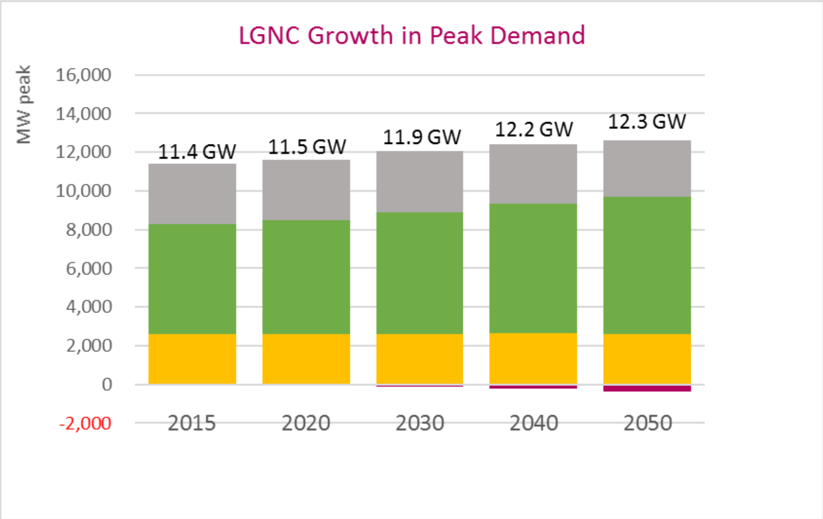


Figure 6: Overall grid BAU and LGNC growth in peak demand

The largest reductions in peak demand growth are in the transmission and high voltage networks where peak demand is predicted to increase by roughly 22% and 23% respectively by 2050 under BAU but by only 8% and 11% under the LGNC scenario. The smallest savings are in the low voltage network where peak demand increases by 25% in BAU and 17% in LGNC by 2050, representing a peak saving of 35%.

Table 15: Increase in peak demand on different levels of the network

NETWORK	2015 (MW)	BAU 2050 (MW)	LGNC 2050 (MW)	BAU % Increase	LGNC % Increase	Peak Savings MW (Δ%)
Transmission	11,354	13,883	12,284	22%	8%	1,599 (63%)
High Voltage	11,426	14,093	12,661	23%	11%	1,432 (54%)
Low Voltage	8,299	10,412	9,676	25%	17%	736 (35%)

It is worth noting that the projections for maximum peak demand in the BAU case are intermediate between the AEMO 2015 and 2016 NEFR forecasts, as shown in Table 16. The peak demand forecast is a combination of the underlying growth, and assumptions regarding LG penetration and assumed consumer reactions to prices, tariffs, and so on. The assumptions on LG penetration are taken from the 2016 NEFR.

The ISF BAU scenario uses underlying growth forecasts as provided by the 2015 NEFR, which are higher than the forecasts contained in the 2016 NEFR. The main difference in the 2016 NEFR is that prices are expected to increase in response to additional costs associated with meeting climate change targets. The discrepancy between these two forecasts is caused by an electricity price effect resulting in lower consumption per consumer. The ISF BAU scenario below does not include this price response in consumption profiles.

Co-incident peak demand for all agents is used to estimate peak demand on network in MW. The ISF model calculates a slightly lower overall peak demand for 2015 when the starting conditions are coincident with the NEFR model. The most relevant estimates to compare are therefore the annual projected growth rates of the scenario. As shown in Table 16, the growth in peak demand in the ISF BAU scenario is between the 2015 NEFR estimate and the 2016 revised estimate.

Table 16: Peak demand forecasts compared: NEFR 2015, NEFR 2016, and ISF BAU

	2015 Medium POE 50[1]	2016 Neutral POE 50[2]	BAU ISF model
2015	12.0 GW	11.9 GW	11.4 GW
2020	12.1 GW	11.8 GW	11.8 GW
2030	13.7 GW	11.6 GW	12.5 GW
2035	14.7 GW	11.6 GW	12.8 GW
Average growth over period	0.99%	-0.1%	0.6%

Note 1 Values include operational peak demand minus any distribution or transmission losses.

We also show that network utilisation is greater in the LGNC scenario, as shown in Figure 7. At 2050, utilisation is between 0.5% higher in the low voltage network and 2.6% in the transmission network. Network utilisation is calculated as actual network load over the maximum possible load on the network:

$$Utilisation = \frac{Actual\ Load\ (MWh)}{8760\ \times\ Peak\ Load\ (MW)}$$

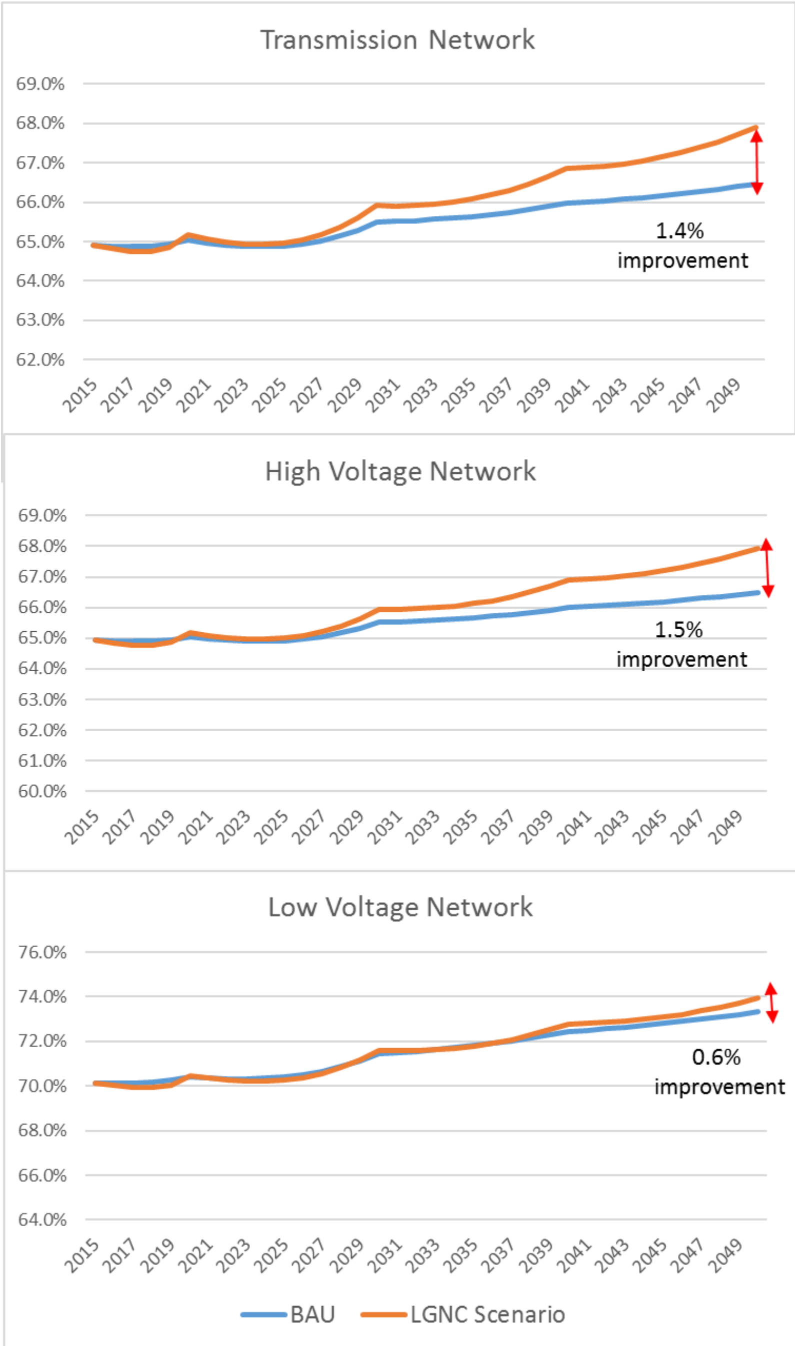


Figure 7: Network utilisation for different network levels

5 RESULTS

The economic analysis compared two scenarios of network costs, under (i) business as usual network expansion, and (ii) when an LGNC payment to distributed generators is offered. The economic costs and benefits of the two scenarios were compared to understand their effects on network costs in NSW. The key assumptions of this analysis were:

- The first year in which network augmentation will be required under BAU is 2025 due to existing spare capacity in the network.
- LGNC payments are not given to existing generators.
- LGNC payments are not given to generators smaller than 10kW.
- There is an 80/20 benefit share of the calculated LGNC (that is, only 80% of the calculated LGNC value is paid to the generator).
- Approximately 2.5% of total repex expenditure is associated with augmentation.

Unless otherwise stated, the results are a combination of results using the Ausgrid and Essential parameters, weighted according to customer numbers on each network *(66% Ausgrid, 34% Essential)*.

The headline result from the economic analysis is that over the long term, an LGNC scenario incurs costs that are $1.18 billion lower than BAU, that is 59% lower than the cost of normal network expansion.

Our modelling estimates the net present value of the cumulative economic costs of network expansion under BAU as approximately $2 billion for NSW by 2050.[19] In comparison, under the LGNC scenario the cumulative cost of network expansion was estimated at $600 million with additional LGNC payments of around $233 million.

Table 17: Cumulative economic cost for NSW by scenario

	2020	2030	2040	2050
BAU				
Network investment	-	$172 m	$939 m	$2,012 m
LGNC payments	-	-	-	-
Total	-	$172 m	$939 m	$2,012 m
LGNC scenario				
Network investment	-	$16 m	$239 m	$598 m
LGNC payments	$6 m	$52 m	$132 m	$233 m
Total	$6 m	$69 m	$371 m	$832 m
Net Economic Benefit	**-$6 m**	**$104**	**$567 m**	**$1,181 m**

[19] This number only represents the cumulative net present value of financing costs. It therefore does not include the actual value of capital investment costs. For example, a capital investment made in 2050 only accounts for the financing costs made up until the year 2050 (i.e. one year of loan repayments for capital expenditure occurring in 2050). For capital investment made in 2049 it would include two years of financing payments. The total net present value of all capital expenditure made until 2050 in NSW is estimated at $7 billion in BAU and $2.5 billion in the LGNC scenario.

Over the short term, the LGNC scenario is more expensive, as our modelling includes sufficient spare network capacity to mean that network augmentation will not be required until 2025. This results in an estimated cost of $6 million in LGNC payments by 2020. We looked at the impact of changing the year when augmentation is first required. If network expansion was required in 2020 as opposed to 2025 under business as usual, there would be a small net benefit of $6m at 2020 from the LGNC. On the other hand, if network expansion was not required until 2028, there would be a cumulative net cost of 28m by 2030. A summary of the cumulative economic costs and benefits for NSW is shown in Table 17 and Figure 8 below.

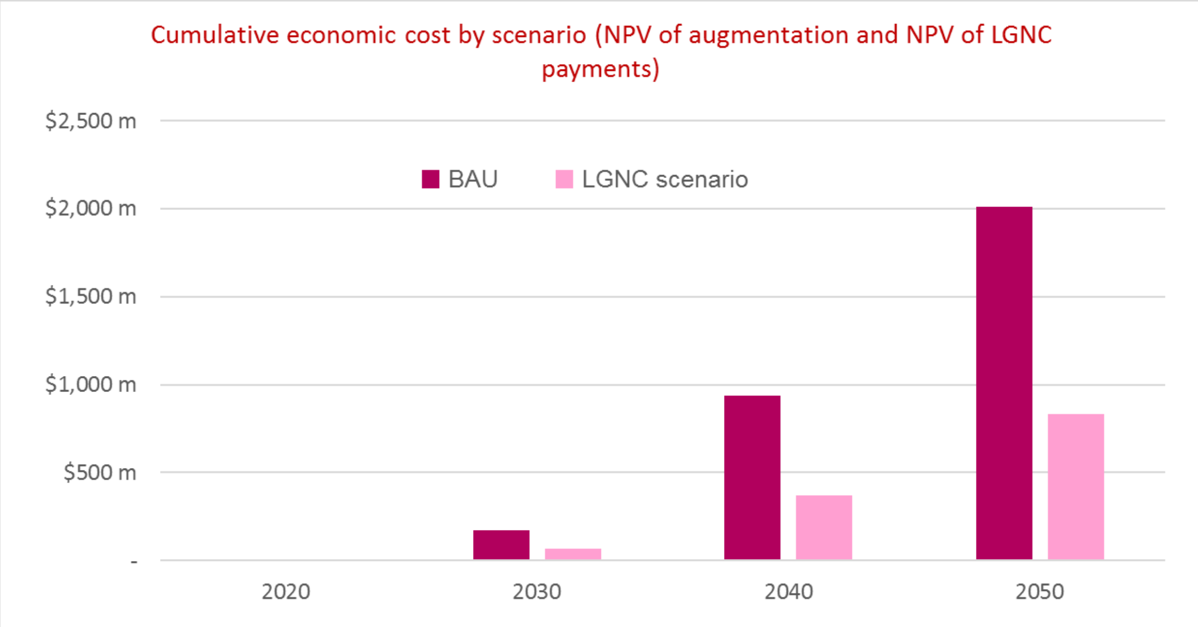


Figure 8: NPV of cumulative economic costs by scenario

Figure 9 shows the NPV of the annual expenditure in each scenario, with the bars representing the total costs in each scenario. In the BAU scenario only the costs associated with network expansion are included as no LGNC payments are made. In the LGNC scenario the costs of network expansion and the costs of making LGNC payments are both included. Over the short term (2020) the LGNC scenario incurs a small annual economic cost, reaching a maximum cost of $4 million in 2024. During this early period LGNC payments are incurred without reducing augmentation expenditure, as it is an input assumption that network augmentation will not be required until 2025 in BAU. In the LGNC scenario spare capacity is not exceeded on the high voltage and transmission networks until the years 2030, and 2031 respectively and 2027 on the low voltage network, representing a delay in network expansion of between two and five years across different network levels. Net economic costs and benefits of the LGNC scenario break even in 2025, and by 2050 there is a $68 m annual benefit. The largest savings in avoided network augmentation occur at higher network levels.

The reduced requirement for network investment occurs because of the reduction in peak load from the increased local generation incentivised by the LGNC payment. This increased generation includes exported electricity and self-consumption. As only the exports receive an LGNC payment, the benefit in reduced network costs is greater than the 20% benefit share factored into the LGNC payment. This model shows that of the 7.5 TWh of additional growth in distributed generation in the LGNC scenario, only 1.5 TWh is actually exported to the grid. As behind-the-meter generation also contributes to avoided network augmentation, the benefit of the LGNC scenario to the grid is multiplied beyond its initial benefit share. This is shown clearly in Figure 9 where the incremental benefit of the LGNC scenario represents a 60% saving from BAU by 2050.

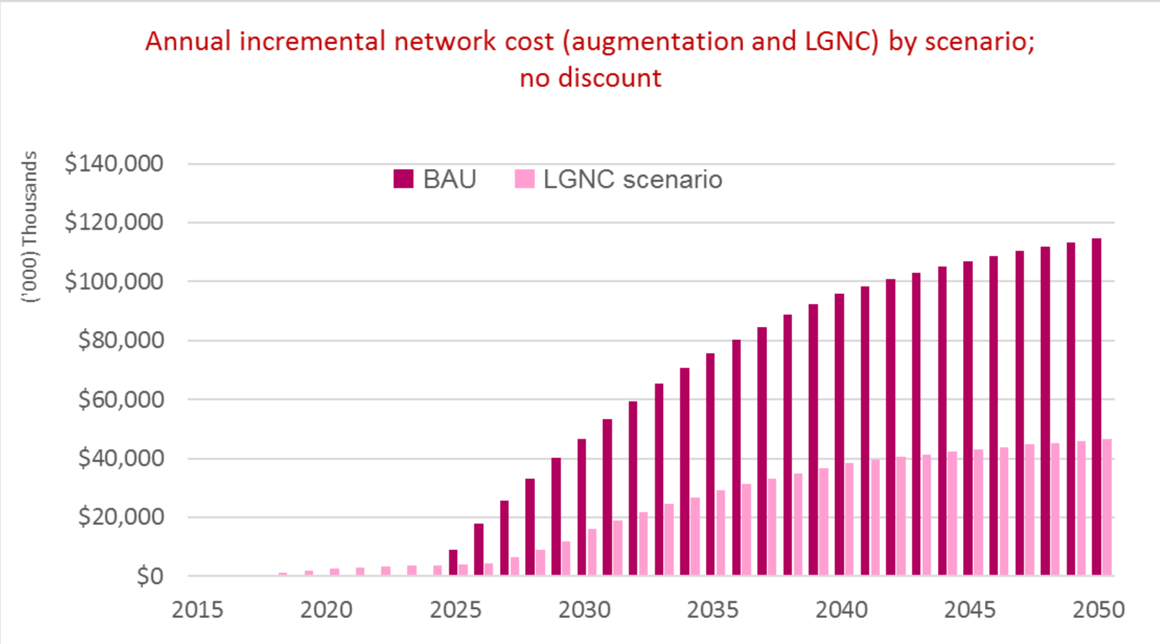


Figure 9: Annual incremental network costs by scenario (no discounting)

These results do not include the savings from transmission losses (MWh of electricity lost from transportation etc.). These values are estimated separately and included as additional information. The analysis does take account of avoided augmentation associated with a reduction in system losses. A reduction in system losses means there will be a reduction in peak load on the network and this represents savings in network augmentation. This is accounted for in the LGNC payment and in the LRMC calculations as avoided network expenditure. Adding this value to the LGNC payment increases system costs, and deducting it from LRMC values decreases system costs. The model does not consider the additional costs of upgrading the distribution network to allow for increased local generation inputs. Table 18 shows the additional savings from electricity losses avoided and the associated augmentation costs that are avoided as a result of the savings in electricity losses. Simple system losses have not been included in the headline figures given above and are therefore additional benefits.

Table 18: NPV of savings avoided system losses ($m)

Electricity losses from GWh avoided	2015	2020	2030	2040	2050
Auxiliary	$0.0 m	$2.1 m	$53.7 m	$143.6 m	$256.6 m
Transmission / System	$0.0 m	$0.3 m	$6.0 m	$15.8 m	$28.1 m

Figure 10 shows the annual net benefit of the LGNC compared to BAU. The red line represents the overall annual net economic benefit of an LGNC scenario compared to business as usual. The bars show how the economic benefits and costs are distributed to different agents. Distributed generators are shown to have an economic disbenefit because they themselves do not benefit from decreased network charges, and the LGNC payments being made are treated as a cost at the system level because LGNC payments are made to local generators. For all other consumers, the benefits of decreased bills outweigh the costs of the LGNC payments made. The associated reduction in augmentation costs is shared as a benefit between all consumers on a volumetric basis. Electricity exporters on the distribution network receive a payment for any exported electricity (which is a cost) but they also avoid future network expansion which is a benefit. As shown, the largest overall benefits accrue to small commercial customers. According to our initial conditions, small commercial customers[20] in NSW represent around 11% by number of all consumers but consume 46% of electricity.

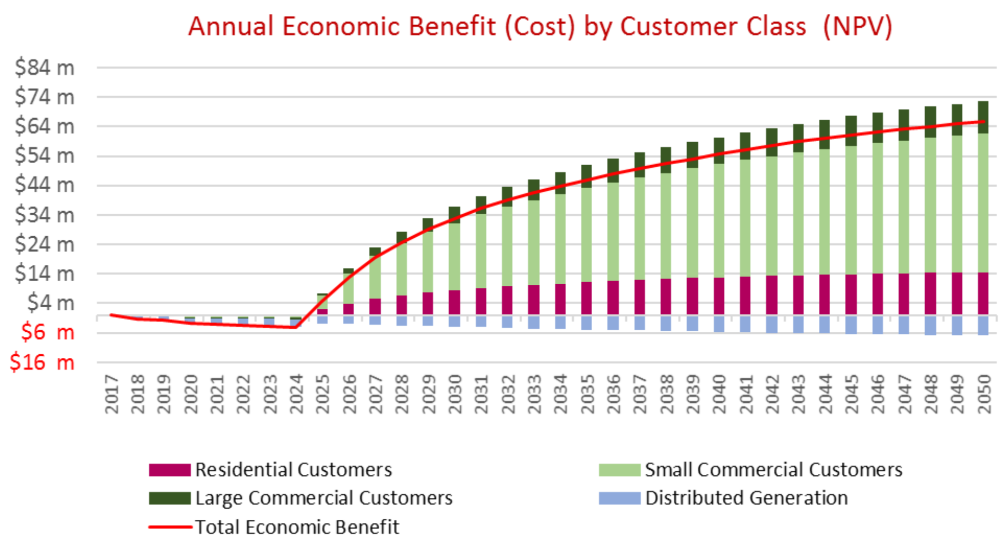


Figure 10: Annual net economic benefits (costs) by customer category

5.1 Impact on customer bills

The average impact on customer bills in the LGNC scenario is positive for all customer classes in the medium and long term, with mixed impacts over the short term, as shown in Table 19 and Table 20. Over the short term, there is no effect on residential customers in the LGNC scenario, as there is no increase in network costs or LGNC payments made owing to the existing spare capacity on the network. Over the short term, small commercial customers will see an increase of $2 per annum and large commercial customers will on average see an increase of $25 per annum in network costs relative to BAU. Those commercial customers directly benefiting from LGNC payments will see average savings of $102 to $2,414 relative to BAU.

Over the medium term (2030) the benefits of LGNC increase across all customer classes. For small commercial customers the medium-term benefit is $140 per annum, and the long-term (2050) benefit is $438 per annum. For large commercial customers there is a saving of $1,693 per year in 2030, and of $5,440 in 2050. Across all customer classes, those customers who generate and export electricity over peak periods receive the largest cost savings, but all customers benefit from reduced bills. The scale of benefit accruing to large commercial customers reflects the size of their consumption.

The average effect on residential customers is less pronounced, with an average drop of $6 per year by 2030 rising to $15 by 2050. The expected impacts on bills (i.e. the difference between the two scenarios) are provided in Table 19 and Table 20.

[20] A small commercial customer is defined as any business that is not a residential customer but still connected to the LV distribution network. On average commercial customers consume 92.3 MWh/year.

Table 19: Net impact of LGNC on consumer bills

$ per year	Average		2020		2030		2050	
Residential	-$9	▼	$0	▲	-$7	▼	-$20	▼
Residential with PV	-$6	▼	$0	▲	-$4	▼	-$13	▼
Residential with PV + battery	-$2	▼	$0	▲	-$1	▼	-$4	▼
Total Residential Customers	-$7	▼	$0	▲	-$6	▼	-$15	▼
Small Commercial	-$185	▼	$4	▲	-$139	▼	-$422	▼
Small Commercial with PV	-$127	▼	$3	▲	-$95	▼	-$289	▼
Small Commercial with PV (includes export)	-$211	▼	-$102	▼	-$184	▼	-$348	▼
Total Small Commercial Customers	-$191	▼	$2	▲	-$140	▼	-$438	▼
Large Commercial	-$367	▼	$14	▲	-$276	▼	-$843	▼
Large Commercial with cogen	-$1,239	▼	-$335	▼	-$1,019	▼	-$2,374	▼
Large Commercial with cogen (includes export)	-$3,050	▼	-$2,414	▼	-$2,889	▼	-$3,869	▼
Total Large Commercial	-$2,341	▼	$25	▲	-$1,693	▼	-$5,440	▼

Table 20: Detailed impact on consumer bills by customer type for each scenario

$ per year	BAU	LGNC	BAU	LGNC	BAU	LGNC	BAU	LGNC
	Average	Average	2020	2020	2030	2030	2050	2050
Residential	$15	$7	$0	$0	$9	$2	$37	$16
Residential with PV	$10	$4	$0	$0	$6	$2	$24	$11
Residential with PV + battery	$3	$1	$0	$0	$2	$0	$8	$3
Average residential	$12	$5	$0	$0	$8	$2	$28	$12
Small commercial	$321	$136	$0	$4	$187	$48	$764	$342
Small commercial with PV	$220	$93	$0	$3	$128	$33	$522	$234
Small commercial with PV + export	$185	-$26	$0	-$102	$108	-$77	$440	$93
Average small commercial	$302	$111	$0	$2	$179	$39	$711	$273
Large commercial	$578	$211	$0	$14	$337	$61	$1,376	$533
Large commercial with cogen	$1,401	$162	$0	-$335	$816	-$203	$3,335	$961
Large commercial with cogen + export	$1,064	-$1,986	$0	-$2,414	$620	-$2,269	$2,534	-$1,335
average large commercial	$3,200	$859	$0	$25	$1,871	$178	$7,596	$2,156

5.2 Sensitivity analysis for peak demand growth

The most significant factor underlying the results of the model may be the growth in peak demand on the network, particularly while we are unable to model reduced replacement benefits which may arise from reducing the capacity of network assets.

Underlying assumptions for peak demand growth in the business as usual case are derived from the AEMO 2015 NEFR medium projection and the 2016 NEFR neutral scenarios, as described in Section 4. However, there are a number of reasons why actual demand could differ significantly from these projections. For example, the response to cost-reflective tariffs could alter demand profiles and move consumption away from peak periods, or the penetration of battery storage could far exceed the scenarios we have modelled. Alternatively, the widespread adoption of electric vehicles could significantly increase demand, with the effect on peak periods mediated by the charging strategies used by consumers. Modelling variations in these multiple areas was beyond the scope of the project, so it was decided to test a significant variation in demand growth as a proxy for all of these factors. The BAU growth rate in peak demand averages at 0.6% per annum over the entire period, and we modelled alternative growth rates ranging from 0.1% per year, to 1.1% per year.

As expected, any reduction in projected growth rates reduces the net economic benefit, and if growth rates drop below 0.2% per year, representing a cost over the entire period ranging from $6m at 2020 to $233 million at 2050. However, the potential benefits and losses are asymmetrical, with potential benefits several times greater than potential losses. At the other end of the spectrum, a growth rate of 1.1% per year in peak demand yields a benefit of $1.5 billion by 2050.

The asymmetry occurs because the costs are capped at the LGNC costs, so the potential loss of $233m at 2050 with a growth rate of 0.2% per year does not increase if growth is reduced further, or even if growth is negative.

However, the asymmetry which would occur in real situations is far greater than this. The LGNC is calculated directly from the LRMC, which is in turn calculated from expected augmentation spending. When there is negative growth on a network, the LRMC value will tend to zero, and with it the LGNC value. This is not reflected in the model, as both LRMC and LGNC values are static inputs. Thus, the real LGNC payment in a situation of sustained negative or flat growth would be zero, leading to a net zero effect overall.

5.3 Net economic benefit according to demand growth

We tested the sensitivity to the growth in peak demand by changing the overall growth rate in peak demand by +80% and by -0.1%.[21] We did this at each stage in the projection; that is, we reduced or increased the growth rate in system peak demand by +80% and -0.1% between 2015 and 2020, 2030 and 2040, etc. We produced the change in demand growth by manipulating the residential sector alone, as the projected growth rates in the residential sector are identical in the BAU and LGNC scenarios, and this sector does not receive any LGNC payments. A reduction in residential growth in the BAU scenario is analogous to the effects of increased battery uptake in a scenario of zero net exports back to the grid.

Figure 11 shows the resulting system peak demand for each growth rate modelled. The dark red line shows the modelled case, which has an average growth rate across the period of 0.6% per year. In the lowest growth case modelled, demand is flat, while the standard case has a projected increase to 14 GW by 2050, and the maximum case has an increase to 16.7 GW.

Figure 12 shows the variation in net economic benefit between now and 2050 according to the growth in peak demand. As would be expected, the benefit from an LGNC is reduced if demand growth is reduced. However, the costs and benefits are asymmetrical, with potential benefits approximately six times greater than potential costs. This asymmetry arises because the costs are capped at the LGNC payments, while the benefits from avoided network augmentation costs result from both the exported energy, which receives an LGNC payment, and the associated behind-the-meter generation.

[21] Note that we could not achieve the -0.1% growth rate between 2040 and 2050 from the residential sector alone, so the growth during that period reverted to 0.2% of the modelled case. This resulted in growth over the entire period of 0.04%, compared to 0.6% in the modelled case, and 0.12% in the 0.2% case.

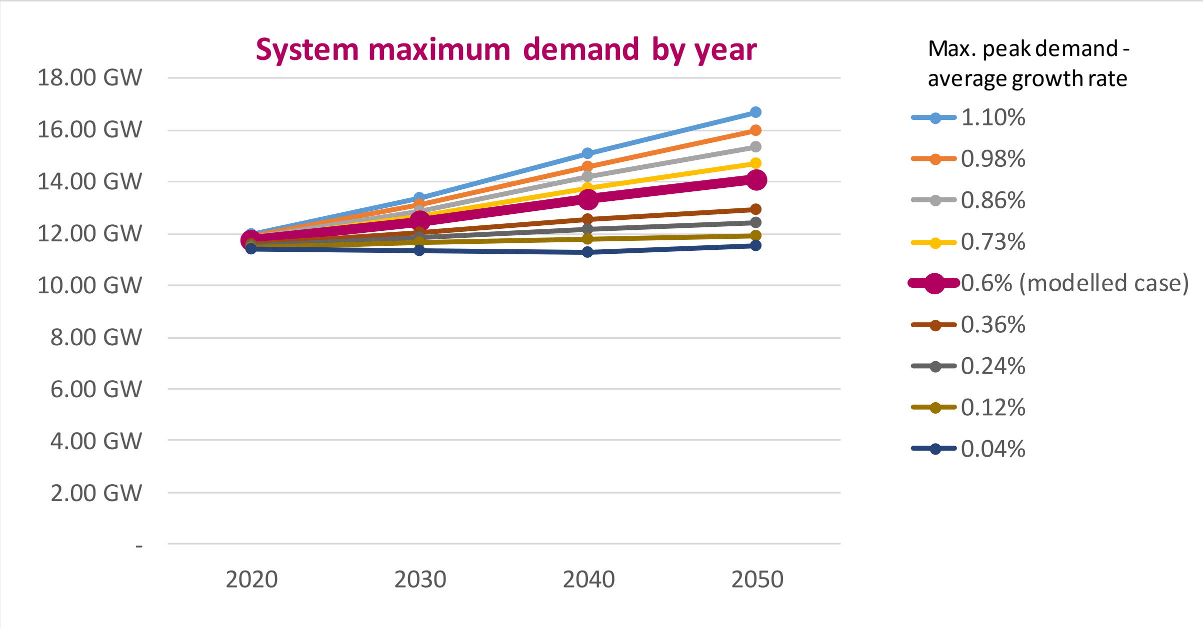


Figure 11: System peak demand by year according to the average growth rate

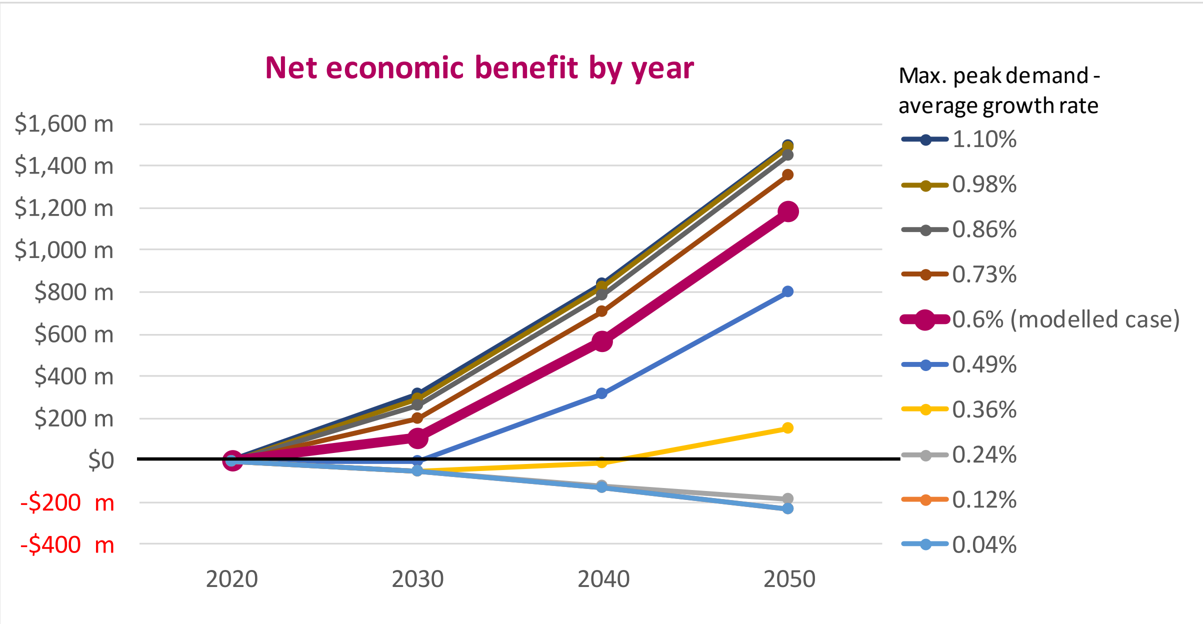


Figure 12: Net economic benefit according to growth rate in peak demand

5.4 Sensitivity analysis – other factors

We undertook sensitivity analysis on a number of other assumptions in the model, namely:

- the year network augmentation is first required on the network
- the rate of growth of local generation in the LGNC scenario compared to BAU
- making LGNC payments to existing dispatchable, non-dispatchable and small systems under 10kW
- the effect of including non-locational transmission costs in the LGNC payments.

Net economic benefits are reduced if the year network augmentation is first required is later, indicating more spare network capacity, and vice versa. However, in all the cases tested (network augmentation first required 2020 and not until 2030), there was a positive economic benefit in the long term. In most cases, there is a positive economic benefit in the medium term.

We tested a smaller and larger increases in local generation in response to the LGNC. In general, if there is less local generation, overall economic benefit is reduced, while if there is a greater uptake in local generation than forecast, the economic benefit increases. We tested reducing the projected growth rate by 50%, and increasing it by 50%. However, while not within the bounds of the +/- 50% sensitivity testing, there will be an inflexion point when more local generation capacity is installed than is required to offset the growth in peak demand on the network. This is because further LGNC payments are made but the benefit of reduced network augmentation is not accrued. This may have design implications for areas of high local generation penetration or low demand growth.

Economic benefits are reduced if existing generators are paid the LGNC. This effect is much more marked in the short term if payments are made to both non-dispatchable and dispatchable generators. The model does not dynamically take into account the behavioural responses of agents to LGNC payments or he effects of altered dispatch strategies for existing generators as LGNC payments change.

Excluding systems under 10kW from LGNC payments

As noted above, modelling was undertaken to understand the impact of excluding LGNC payments to systems smaller than 10 kW. We examined the effects of including and excluding systems under 10 kW in the LGNC. There were two effects: firstly, the cumulative effect of excluding systems under 10kW increased the cumulative economic benefits in 2030 from $-9m to $104m. Secondly, when existing systems under 10kW are included in the payments, residential customers receive 66% of LGNC payments in 2020 and 58% of the payments in 2030. Figure 13 shows the major recipients receiving LGNC payments under the condition of excluding 10kW systems. Under these conditions payments to existing generators are excluded in both cases. Table 21 shows the cumulative overall cost benefit when small systems are included.

We consider it relatively unlikely that rooftop PV systems will be incentivised by an LGNC, as the additional value of an LGNC is much less significant than small changes in the installation cost, and the residential market is arguably less influenced by strictly economic factors. In addition, rooftop PV systems are less likely to result in network benefits than commercial systems, as they are non-dispatchable, and more likely to be located in areas with evening peaks. Table 21 shows the economic costs and benefits of including 10kW systems in the LGNC payments. Please note that this table excludes all existing generation.

Figure 13: LGNC payments by recipient (existing generators excluded)

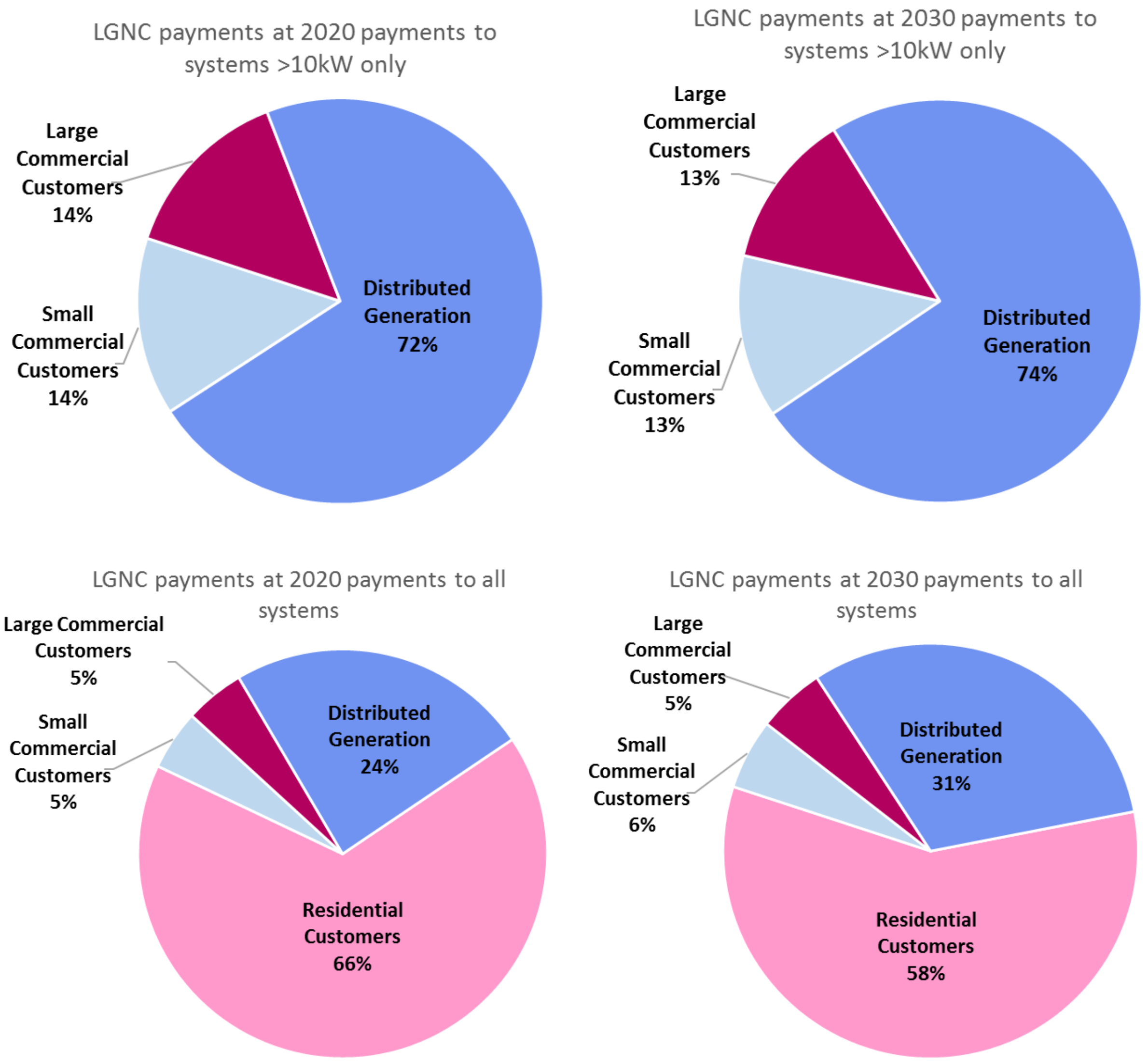


Table 21: LGNC paid to all new systems: cumulative economic cost by scenario (NPV)

	2020	2030	2040	2050
BAU network investment	-	$172 m	$939 m	$2,012 m
LGNC Network investment	-	$8 m	$185 m	$494 m
LGNC payments (paid to ALL systems)	$23 m	$174 m	$390 m	$627 m
Total	$23 m	$182 m	$575 m	$1,121 m
Net Economic benefit	**-$23 m**	**-$9 m**	**$363 m**	**$891 m**

This table excludes all existing generation (dispatchable and non-dispatchable).

Excluding existing generators from LGNC payments

The results in Table 21 exclude all existing systems. If, however, payments are made to existing systems, the outcome at 2020 would be a cost of $102m, rather than a cost of -$23m, and at 2030 there would be a cost of $290m, rather than a cost of $9m. These costs are excessive, especially when the LGNC is not incentivising additional generation. Thus, in addition to excluding systems under 10kW, LGNC payments should also exclude existing systems.

Sensitivity testing showed that the economic benefits were significantly lower if the LGNC was paid to existing generators, particularly in the short term. The benefit reduction is greater if payments are made to dispatchable generators, as there is very little existing distributed non-dispatchable generation left once small systems (<10kW) are excluded.

Other work has shown that an LGNC is likely to incentivise exports from cogeneration at peak times, whereas it may otherwise be marginal, which is likely to increase economic benefits. However, if only existing dispatchable generation is included (i.e. existing non-dispatchable and systems are 10kW are excluded) the economic benefit in 2030 will be $42m as opposed to $104m. We therefore modelled the results excluding any payments to existing local generators and future payments to systems under 10kW. This should be examined in more detail at a later stage, as it may be advantageous to include those sub-classes of dispatchable generators most likely to respond to an LGNC payment and avoid future network augmentation. However, the benefit may be outweighed by the complications of implementing a payment system which only applies to some existing generators.

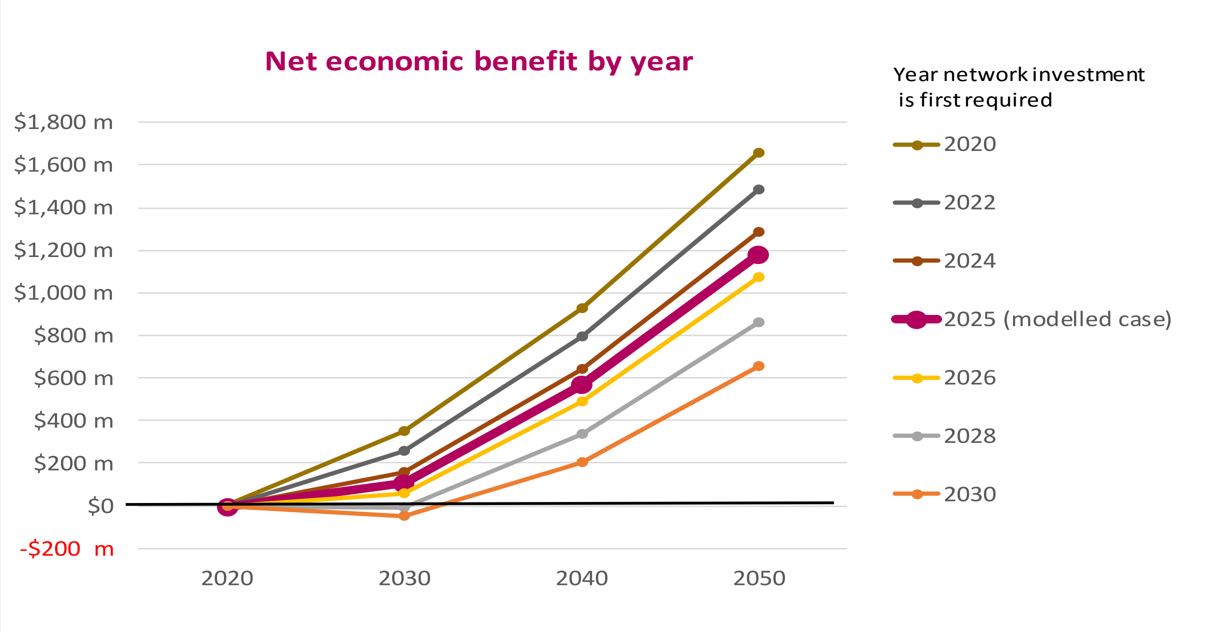
Net economic benefit by year network augmentation required

In the modelled case, we assumed the network would first require augmentation in 2025 in the BAU scenario. The later the year chosen, the lower will be the benefit delivered from the LGNC payments. This is because the LGNC is paid immediately, while the avoided network costs only occur when the network would otherwise have reached critical capacity. Table 22 shows the cumulative net economic benefits at 2020, 2030, 2040, and 2050 according to the year augmentation is first needed in the absence of an LGNC. If augmentation would not be needed until 2028, there would be a dis-benefit at 2030 of approximately $12m.

Table 22: Net economic benefit by year network augmentation first required (cumulative costs)

Investment first required under BAU	Net economic benefit of LGNC at			
	2020	2030	2040	2050
2020	-$6 m	$349 m	$929 m	$1,658 m
2022	-$6 m	$254 m	$794 m	$1,483 m
2024	-$6 m	$153 m	$644 m	$1,285 m
2026	-$6 m	$56 m	$486 m	$1,069 m
2028	-$6 m	-$12 m	$337 m	$858 m
2030	-$6 m	-$47 m	$202 m	$655 m

Figure 14: Net economic benefit of LGNC by the year network augmentation required



Sensitivity of model to growth in local generation

We tested the net economic benefit for growth rates at 50% below and 50% above the modelled LGNC scenario. Figure 15 shows the range in generation from different distributed generation systems used in the sensitivity tests.

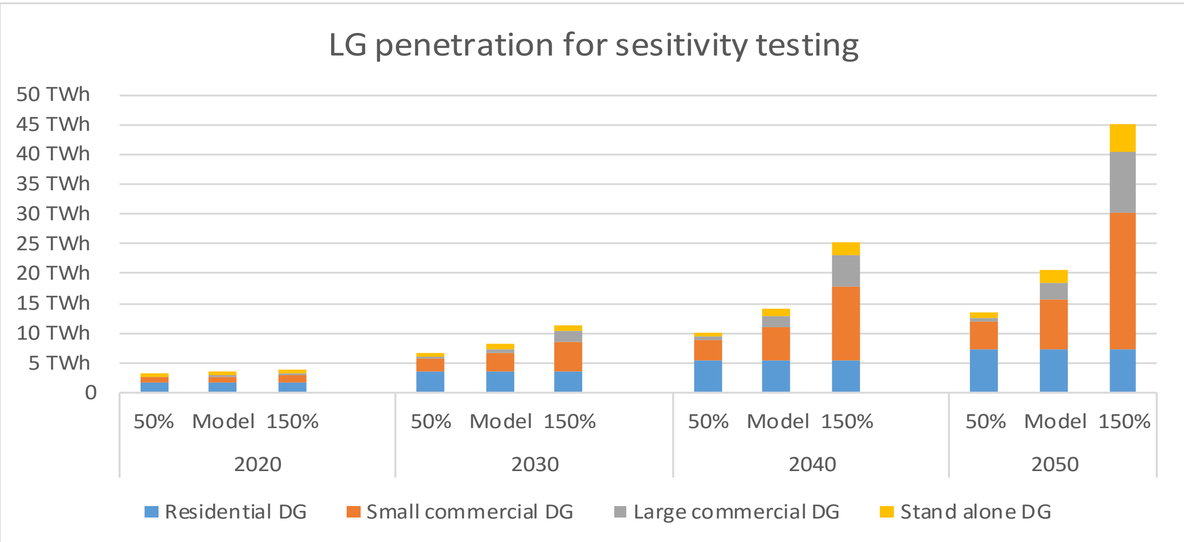


Figure 15: Penetrations of LG examined in the sensitivity tests

The resulting numbers of agents in the two customer classes relevant to the LGNC scenario are shown in Table 23. We have excluded residential customers with PV as they would not be affected by the LGNC in the modelled case, as all systems under 10kW are excluded from LGNC payments. The modelled penetrations for all customer classes and for BAU are shown in Table 31.

Table 23: Modelled case and sensitivity tests – number of agents in each category

		2015	2020	2030	2040	2050
Small Commercial with PV and LGNC	- 50%	100	4,260	8,440	13,528	18,340
	modelled	100	8,520	28,798	64,892	107,522
	+ 50%	100	12,780	71,729	224,680	453,218
Total small commercial agents		407,330	425,993	479,963	540,770	597,346
Large Commercial with cogen including exports	- 50%	10	91	169	252	325
	modelled	10	183	576	1,210	1,908
	+ 50%	10	274	1,434	4,190	8,044
Total large commercial agents		49,463	50,712	53,306	56,032	58,897

GROWTH RATE		*2015-2020*	*2020-2030*	*2030-2040*	*2040-2050*
Distributed generation (wind, solar, bioenergy, gas, diesel, hydro)	- 50%	1.6%	1.6%	1.6%	1.6%
	modelled	3.1%	3.1%	3.1%	3.1%
	+ 50%	4.7%	4.7%	4.7%	4.7%

Table 24 gives the net economic benefit under the altered growth rates. In general, any reduction in local energy results in a reduction in overall societal benefit.

Table 24: Net economic benefit by growth rates of DG (cumulative costs)

	2020	2030	2040	2050
LG growth rate reduced by 50% (LGNC case only)	-$3 m	$37 m	$122 m	$213 m
Modelled case	-$6 m	$104 m	$567 m	$1,181 m
LG growth rate increased by 50% (LGNC case only)	-$9 m	$78 m	$657 m	$1,442 m

Net economic benefit by whether existing generators are paid the LGNC

Table 25 and Table 26 show the net economic benefits when the LGNC excludes all existing generators, and when it includes all existing generators. The tables also show the impact of including only dispatchable generators, and of including only non-dispatchable generators. Table 25 does not include small systems under 10kW, while Table 26 includes all systems.

Paying existing generators an LGNC payment reduces the economic benefit overall, and particularly so in the early years. This finding was expected, as during the first few years there is sufficient spare capacity in the network to account for growth out to 2025. In addition, paying an LGNC to existing non-dispatchable generators will not lead to any different outcomes in terms of dispatch at different times, so there would not be any incremental benefit for making these payments.

When LGNC is not paid to small systems (Table 25**):** the results show that excluding existing generators from LGNC payments has a significantly better outcome than paying existing generators. The cost of including non-dispatchable generators is small when small systems under 10kW have already been excluded. This is because once small systems have been excluded, the majority of remaining distributed generation is dispatchable, and would therefore all be eligible to receive the LGNC (433 GWh).

When LGNC is paid to small systems (Table 26**):** if existing small systems under 10kW are included in LGNC payments there will be negative economic benefits up until 2030 across all scenarios.

It should be noted that this iteration of the model did not include behaviour change from existing generators in response to an LGNC. While non-dispatchable generators could not react to an LGNC, dispatchable generators could increase exports during peak time, which would have a consequent economic benefit. The scale of this response should be investigated prior to deciding whether to include or exclude existing dispatchable generators in any future LGNC payment, and whether sub-classes of dispatchable generators should be included.

Table 25: Net economic benefit according to whether the LGNC is paid to existing generators (small systems *excluded*)

Network parameters: Ausgrid	2020	2030	2040	2050
Exclude all existing generators (modelled case)	-$5.34	$104 m	$567 m	$1,181 m
Include all existing generators	-$25 m	$34 m	$465 m	$1,057 m
Include dispatchable only	-$23 m	$42 m	$477 m	$1,071 m
Include non-dispatchable only	-$8 m	$95 m	$555 m	$1,166 m

Table 26: Net economic benefit according to whether the LGNC is paid to existing generators (small systems *included*)

Network parameters: both	2020	2030	2040	2050
Exclude all existing generators	-$23 m	-$9 m	$363 m	$891 m
Include all existing generators	-$102 m	-$290 m	-$52 m	$387 m
Include dispatchable only	-$40 m	-$70 m	$273 m	$781 m
Include non-dispatchable only	-$85 m	-$229 m	$39 m	$497 m

Net economic benefit according to inclusion or exclusion of non-locational transmission values

We calculated the net economic benefit with and without the inclusion of non-locational transmission values in the LGNC payments. The overall net benefit was not affected significantly, with a net reduction in benefit of $254m by 2050 if non-locational charges are excluded.

Table 27: Net economic benefit according to whether non-locational transmission costs are included in LRMC payments

	Net economic benefit of LGNC at			
	2020	2030	2040	2050
Non locational charges included	-$6 m	$104 m	$567 m	$1,181 m
Non locational charges excluded	-$2 m	$99 m	$456 m	$927 m

6 CONCLUSION

The results show that there is an overall economic benefit to society from providing an LGNC payment, with cumulative cost savings in the order of $104m in 2030 and $1.2 billion by 2050. We estimate that the net cost of paying of a Local Generation Network Credit, combined with the reduced cost of network augmentation, is 59% lower than the cost of normal network expansion by 2050 in a business as usual scenario.

Modelling of LGNC payments shows an economic benefit for all NSW consumers in the medium and long term, with a small cost in the short term. The LGNC scenario shows an economic benefit for all consumers after five to ten years, as it results in a decrease in consumer bills through a reduction in the overall network expansion costs. The reduction in costs is most marked for those customers who interact with the grid the most through net import consumption or net exports. Those customers who generate behind the meter are shown to benefit the least. Small commercial customers receive bill reductions relative to business as usual of $140 per annum in 2030 and $438 in 2050.[22] Large commercial customers receive bill reductions relative to business as usual of $1,693 per annum in 2030 and $5,440 in 2050.[23] There are only very moderate effects on residential customers, with no short-term impact and a small long-term reduction in consumer bills compared to BAU. Standard residential consumers stand to benefit the most, with bill reductions of $20 per annum on average compared to BAU.

The size of the benefit is highly dependent on the growth in peak demand, with higher projected growth leading to greater benefits from an LGNC. However, costs and benefits are asymmetric. In reality, costs in a zero or negative growth situation would tend towards zero, as LGNC payments are calculated from the value of the LRMC, which would itself tend to zero. This effect is not included in the model.

This modelling has resulted in the following design recommendations: LGNCs should not be paid to existing non-dispatchable generators, or to generators under 10kW, as excluding these generators maximises the economic benefits to all consumers. However, there should be further investigation of whether payments to sub-classes of dispatchable generators would have an overall cost benefit.

The modelling results inherently depend on a range of assumptions, which we have endeavoured to make as transparent as possible. We also acknowledge that the time horizon considered is long, particularly in an industry that is undergoing quite fundamental changes. It is therefore necessary to highlight the uncertainty with which future scenarios are created, and it would be prudent to give more weight to results that occur earlier. However, it should also be remembered that most network assets have a lifetime in the order of 40 years or more, so investment and market decisions require long forward projections.

6.1 Future work

There are a number of ways the model could be improved to both more accurately reflect real conditions, and to test alternative settings to inform design choices for an LGNC. Areas of work to develop the model include:

1) **Model the economic impacts per network region or sub-region**: This would require network specific parameters for customer numbers, projected growth, agent

[22] An average small commercial customer has a gross consumption of 92,290 KWh per annum

[23] Standard large commercial customers have gross consumptions of 293,253 KWh per annum and large commercial customers with cogen have gross consumption of 1,666,667 kWh.

profiles, and spare capacity. At present the LRMC values, periods, and LGNC values are network specific, but other data is for the state as a whole. A deeper understanding of these factors would help to inform LGNC design decisions if LGNCs were to be applied at a granularity below the network-wide level.

2) **Incorporate dynamic modelling of the LRMC and LGNC values** to allow for low or zero growth situations.

3) Re-run the model with an updated projection once electric vehicles have been incorporated into forecasts. The future uptake of electric vehicles and their effect on peak demand has not been anticipated by the AEMO projections. We propose to model the effect that electric vehicles may have on network peak demand.

4) **Understand and incorporate the potential impacts on replacement costs** corresponding to the potential for local generation to result in downsizing network capacity, to include in the overall costs and benefits of impacts. This is particularly important if we are moving into a time of potential reductions in maximum peak demand.

5) **Develop a function for the relationship between battery uptake and dispatch response to LGNC payments:** at present the model does not include any effect of the LGNC on battery uptake, and the penetration rate of batteries and solar is the same in both scenarios. In order to include the effect that LGNC payments may have on battery uptake and/ or discharge strategies, there would need to be further research to develop the relationship function, and additional work to include altered dispatch strategies in the model.

6) **Allow feedback within the model to estimate uptake rates of local generation relative to the value of the LGNC payment:** this will allow the model to test different response rates to different LGNC levels. At present, these assumptions are exogenous to the model, and would ideally be connected so that alterations in LRMC values (and therefore LGNC values) would flow through to expansions or reductions in local generation.

7) **Investigation of the cost benefit of an LGNC payment to sub-classes of dispatchable generators:** other work has demonstrated that the LGNC payment is sufficient to incentivise exports from existing cogeneration. The model should be modified to test whether payments to this class of existing generators has an overall cost benefit.

8) **Implement a probabilistic model for demand per agent:** currently consumption profiles represent the average behaviour of all consumers within a representative agent category. However, this does not capture the heterogeneity of different consumers, producers and prosumers in the network. A probabilistic model will need to be developed in which agents can be sampled from known distributions.

9) **Implement a probabilistic model for generation from non-dispatchable sources (solar and wind):** at present the model assumes average solar generation on a typical summer day; however, development of a probabilistic model to sample from possible generation profiles would more accurately reflect the effects of intermittency over the year.

It is recommended that this work be undertaken in order to inform the detailed development of an LGNC to maximise benefits for electricity consumers.

APPENDIX A: INITIAL CONDITIONS

Table 28: Non-scheduled distributed generation in NSW by total capacity and count

Non Scheduled Generation	Total stand-alone generation		Under 30MW		Assumed behind the meter
	MW	Count	MW	Count	
Bagasse	68	2	0	0	yes
Biomass recycled municipal and industrial material	4	1	4	1	yes
Coal seam methane	7	1	7	1	no
Diesel	130	8	38	6	yes
Landfill methane / landfill gas	57	15	57	15	no
Natural gas – unprocessed	16	2	16	2	yes
Natural gas pipeline	9	8	9	8	yes
Solar farms	20	0	20	2	no
Waste coal mine gas	111	4	14	2	no
Water	220	15	136	13	no
Wind	186	5	15	3	no
Total	**828**	**61**	**317**	**53**	

Table 29: Non-scheduled generation in NSW by generation

Non Scheduled Generation	MW	GWh
Broadwater and Condong bagasse generators [1]	68	149
Tower and Appin coal seam methane generators [2]	97	654
Solar farms under 30 MW [3]	20	30
Wind generators under 30 MW [4]	15	34
Large commercial [5]	67	116
Other Distributed Generation [6]	214	370
Total non-scheduled generation [7]	**482**	**1,352**

1. Calculated from an assumed capacity factor of 25%
2. Appin Tower & Westcliff Power Stations, www.energydevelopments.com
3. Calculated from an assumed capacity factor of 17%
4. Calculated from an assumed capacity factor of 25%
5. Calculated from using estimated behind-the-meter capacity and average capacity factor for remaining Non-Scheduled generation (20%)
6. Calculated as the remaining distributed generation on the system
7. AEMO 2016 NEFR forecast for non-scheduled generation for NSW, reduced by the AEMO growth rate for NSW of 0.87%. AEMO advised that this forecast included the output from Tower, Appin, Broadwater and Condong generators.
8. The remaining generation after output from >30MW plant, solar and wind is then divided into large commercial and "other", using the capacities as shown in Table 29 and the average capacity factor of 36%. "Other" includes hydro, landfill gas, coal seam methane, and waste coal mine gas

Table 30: Solar farms in NSW

Solar Farms in NSW	Capacity (MW)	Generation (MWh)
Broken Hill	54	78,506
Moree	57	82,867
Nyngan	102	148,289
Capitl east	1	1,454
Royalla	20	29,076
Assumed capacity factor	17%	
Proportion of Distributed	9%	
TOTAL	**234**	**340,192**
Total Distributed solar	**21**	**30,530**

Table 31: Aggregate gross generation and net export generation by agent in 2015

Representative agent type	2015 Gross Generation (GWh)	2015 Gross Generation Share (%)	2015 Net Exports (GWh)	2015 Net Exports Share (GWh)
B - Residential + PV	1219	60%	714	52%
C - Residential + PV + Battery	-	-	-	-
E - Small Commercial + PV	267	13%	-	-
F - Small Commercial + export	4	0%	-	-
H - Large Commercial + cogen	105	5%	6	0%
I - Large Commercial + cogen + export	12	1%	1	0%
J - Wind Power	28	1%	28	2%
K - Solar Farm	31	2%	31	2%
L - Non Scheduled Generation	370	18%	370	27%
Total	**2035**	**100%**	**1364**	**100%**

APPENDIX B: LRMC VALUES

DISTRIBUTION LRMC VALUES

LRMC values for sub-transmission, high-voltage and low voltage were estimated using the Energeia LRMC calculator, which was commissioned by the Institute for Sustainable Futures as part of the *Facilitating Local Network Charges and Virtual Net Metering* project. Transmission LRMC values were estimated from publicly available data. The methodology and the model are available from the website http://bit.do/Local-Energy.

These values are the system-wide values for the two networks, excluding the LRMC associated with new connections, and with 2.5% of total repex growth assumed to be associated with augmentation.

TRANSMISSION LRMC VALUES

Transmission LRMC values were estimated from the locational and non-locational price component charges levied on DNSPs for prescribed TUoS services.

Locational

The locational value calculation mirrors the commonly used method for avoided TUoS calculation from locational charges

$$Estimated\ locational\ LRMC = Network\ average\ locational\ charges \times 12 \times powerfactor$$

Where

- Estimated locational LRMC is in units of \$/kVA/year.
- Network Average Locational Charges are in units of \$/kW/month.
- Power factor is in units of kW/kVA, a value of 0.97 was used.
- There are 12 months in a year.

Network average locational charges were calculated as a maximum demand weighted average of published Transgrid charges (Transgrid 2015a) weighted according to 2015/16 Bulk Supply Point (BSP) maximum demand (Transgrid 2015c). Only BSPs for which maximum demand data could be obtained were used in the calculation. The BSPs included in calculating the weighted average locational charges for each network were:

Ausgrid: Beaconsfield 132, Haymarket 132, Liddell 330, Munmorah 132, Muswellbrook 33, Newcastle 132, Sydney East 132, Sydney North 132, Sydney South 132, Top Ryde 132 and Waratah West 132.

Essential: Albury 132, Armidale 66, Balranald 22, Beryl 66, Broken Hill22, Broken Hill 220, Casino Tee 132, Coffs Harbour 66, Cooma 11, Cooma 132, Cooma 66, Cowra 66, Darlington Pt. 132, Deniliquin 66, Dorrigo 132, Finley 132, Finley 66, Forbes 66, Glen Innes 66, Griffith 33, Gunnedah 66, Hawks Nest , Herons Creek , Inverell 66, Kempsey 33, Kempsey 66, Koolan 66, Lismore 132, Macksville 132, Manildra 132, Marulan 132, Morven 132, Molong 66, Moree 66, Mudgee Tee 132, Munyang 33, Murrumbateman 132, Nambucca 66, Narrabri 66, Orange 66, Orange North 132, Panorama 66, Parkes 132, Parkes 66, Port Macquarie 33, Queanbeyan 66, Raleigh 132, Snowy Adit 132, Stroud 132, Tamworth 66, Taree 33, Taree 66, Tenterfield 22, Tumut 66, Wagga 66, Wagga North 132, Wagga North 66, Wallerawang 132, Wallerawang 66, Wellington 132, Wellington Tee 132, Yanco 33, Yass 132 and Yass 66

The resultant locational charges used were

- Essential: 4.108 $/kW/month
- Ausgrid: 2.156 $/kW/month

Non-locational

To estimate the LRMC attributed to non-locational prescribed TUoS services, the non-locational volumetric charge was used (Transgrid 2015b).

$$Estimated\ non-locational\ LRMC = Non-locational\ Prices \times 8760 \times powerfactor$$

Where:

- Non-locational prices are in units of $/kWh.
- There are 8760 months in a year.
- Power factor is in units of kW/kVA, a value of 0.97 was used.

Table 32: Average Incremental Cost ($/kVA/Year) – values used in model

	Essential	Ausgrid
Transmission (total)	**124.38**	**101.60**
Non-locational	**76.56**	**76.56**
Locational	**47.82**	**25.04**
ST (Total)	**26**	**7**
Augex	19	4
Opex	5	1
Repex	1	2
Connex	0	0
HV (Total)	**171**	**45**
Augex	127	33
Opex	43	11
Repex	1	1
Connex	0	0
LV (Total)	**346**	**161**
Augex	224	91
Opex	102	47
Repex	20	22
Connex	0	0

APPENDIX C: LGNC VALUES AND PARAMETERS

AUSGRID VALUES

Values in the tables below are based on an 80% benefit share (80% of the benefit is paid to generators), so they have been reduced by 20% compared to the calculated Ausgrid LGNC tariff used in the Willoughby trial.

Table 33: Ausgrid LGNC Values[24]

AUSGRID	VOLUMETRIC TARIFF TOTAL $/kWh					
NETWORK CONNECTION LEVEL	1	2	3	4	5	6 [25]
Peak	0.1006	0.0717	0.0617	0.0523	0.0504	0.0483
Shoulder	0.0041	0.0029	0.0025	0.0021	0.0021	0.0020
offpeak	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

Table 34: Ausgrid billing periods

AUSGRID	Peak and offpeak periods	
WEEKDAYS	Start	Finish
off Peak	22:00	07:00
shoulder	07:00	14:00
Peak	14:00	20:00
shoulder	20:00	22:00

Table 35: Ausgrid annual hours and probability of peak

AUSGRID	ANNUAL HOURS AND PROBABILITY OF PEAK		
	Peak	Shoulder	Offpeak
Annual Hours	1,566	4,274	2,920
Peak Probabilities	90%	10%	0%

[24] The economic model uses 1 for low voltage networks, 3 for high voltage networks, 5 for sub-transmission and 6 for transmission.

[25] Only transmission avoided

ESSENTIAL VALUES

Values in the tables below are based on an 80% benefit share (80% of the benefit is paid to generators), so they have been reduced by 20% compared to the calculated Essential LGNC tariff used in the Byron trial.

Table 36: Essential LGNC values

Essential	VOLUMETRIC TARIFF TOTAL $/kWh					
NETWORK CONNECTION LEVEL	1	2	3	4	5	6 A
Peak	0.0772	0.0584	0.0434	0.0290	0.0239	0.0236
Shoulder	0.0632	0.0478	0.0355	0.0237	0.0196	0.0193
offpeak	0.0117	0.0089	0.0066	0.0044	0.0036	0.0036

Table 37: Essential billing periods

Essential		
WEEKDAYS	Start	Finish
Offpeak	19:30	7:00
Peak	07:00	08:30
Shoulder	08:30	16:30
Peak	16:30	19:30
WEEKENDS	offpeak	

Table 38: Essential annual hours and probability of peak

Essential	ANNUAL HOURS AND PROBABILITY OF PEAK		
	Peak	Shoulder	Offpeak
Annual Hours	1,305	2,871	4,584
Peak Probabilities	30%	54%	16%

APPENDIX D: SCENARIO ASSUMPTIONS

Table 39: Average annual growth rate of consumers within each category

BAU Scenario	Average annual growth between periods				
Agent type	*2015-2020*	*2020-2030*	*2030-2040*	*2040-2050*	2015-2050
	%	%	%	%	
A - Residential	0.09%	-0.22%	-0.26%	-0.40%	-0.24%
B - Residential + PV	3.51%	4.07%	3.48%	1.97%	3.22%
C - Residential + PV + Battery	270.74%	17.69%	6.35%	4.53%	30.21%
Total Residential Customers	0.90%	1.20%	1.20%	1.00%	1.10%
D - Small Commercial	0.33%	0.26%	0.64%	0.52%	0.45%
E - Small Commercial + PV	18.09%	11.77%	4.27%	2.93%	7.87%
F - Small Commercial + export	0.90%	1.20%	1.20%	1.00%	1.10%
Total Small Commercial Customers	0.90%	1.20%	1.20%	1.00%	1.10%
G - Large Commercial	0.47%	0.46%	0.45%	0.43%	0.45%
H - Large Commercial + cogen	3.09%	3.08%	3.10%	3.08%	3.09%
I - Large Commercial + cogen + export	0.50%	0.50%	0.50%	0.50%	0.50%
Total Large Commercial Customers	0.50%	0.50%	0.50%	0.50%	0.50%
J - Wind Power	3.10%	3.10%	3.10%	3.10%	3.10%
K - Solar Farm	3.10%	3.10%	3.10%	3.10%	3.10%
L - Other (wood, biogas, diesel, cogen)	3.10%	3.10%	3.10%	3.10%	3.10%
Total Local generation	3.10%	3.10%	3.10%	3.10%	3.10%
LGNC Scenario	**Average annual growth between periods**				
Agent type	*2015-2020*	*2020-2030*	*2030-2040*	*2040-2050*	2015-2050
	%	%	%	%	%
A - Residential	0.09%	-0.22%	-0.26%	-0.40%	-0.24%
B - Residential + PV	3.51%	4.07%	3.48%	1.97%	3.22%
C - Residential + PV + Battery	270.74%	17.69%	6.35%	4.53%	30.21%
Total Residential Customers	0.90%	1.20%	1.20%	1.00%	1.10%
D - Small Commercial	-0.09%	-0.25%	-0.23%	-0.52%	-0.30%
E - Small Commercial + PV	18.09%	11.77%	4.27%	2.93%	7.87%
F - Small Commercial + export	143.27%	12.95%	8.46%	5.18%	22.07%
Total Small Commercial	0.90%	1.20%	1.20%	1.00%	1.10%
G - Large Commercial	0.08%	0.03%	-0.23%	-0.31%	-0.13%
H - Large Commercial + cogen	3.09%	3.08%	3.10%	3.08%	3.09%
I - Large Commercial + cogen + export	79.19%	12.17%	7.71%	4.66%	16.23%
Total Large Commercial	0.50%	0.50%	0.50%	0.50%	0.50%
J - Wind Power	4.65%	4.65%	4.65%	4.65%	4.65%
K - Solar Farm	4.65%	4.65%	4.65%	4.65%	4.65%
L - Other (wood, biogas, diesel, cogen)	4.65%	4.65%	4.65%	4.65%	4.65%
Total Local generation	4.65%	4.65%	4.65%	4.65%	4.65%

Table 40: Numbers of consumers within each category

BAU Scenario	Customer Numbers				
Agent type	***2015***	***2020***	***2030***	***2040***	***2050***
A - Residential	2,849,461	2,861,700	2,799,614	2,726,672	2,619,080
B - Residential + PV	339,633	403,573	601,259	846,793	1,028,924
C - Residential + PV + Battery	100	70,042	356,998	660,498	1,028,924
Total Residential Customers	3,189,194	3,335,314	3,757,871	4,233,963	4,676,929
D - Small Commercial	397,954	404,589	415,050	442,217	465,784
E - Small Commercial + PV	9,276	21,300	64,795	98,420	131,416
F - Small Commercial + LGNC	100	105	118	133	147
Total Small Commercial Customers	407,330	425,993	479,963	540,770	597,346
G - Large Commercial	8,787	8,996	9,419	9,851	10,287
H - Large Commercial + cogen	105	122	165	224	303
I - Large Commercial + cogen + export	10	10	11	11	12
Total Large Commercial Customers	8,903	9,128	9,595	10,086	10,601
LGNC Scenario	**Customer Numbers**				
Agent type	***2015***	***2020***	***2030***	***2040***	***2050***
A - Residential	2,849,461	2,861,700	2,799,614	2,726,672	2,619,080
B - Residential + PV	339,633	403,573	601,259	846,793	1,028,924
C - Residential + PV + Battery	100	70,042	356,998	660,498	1,028,924
Total Residential Customers	3,189,194	3,335,314	3,757,871	4,233,963	4,676,929
D - Small Commercial	397,954	396,173	386,370	377,457	358,408
E - Small Commercial + PV	9,276	21,300	64,795	98,420	131,416
F - Small Commercial + LGNC	100	8,520	28,798	64,892	107,522
Total Small Commercial	407,330	425,993	479,963	540,770	597,346
G - Large Commercial	8,787	8,824	8,854	8,652	8,390
H - Large Commercial + cogen	105	122	165	224	303
I - Large Commercial + cogen + export	10	183	576	1,210	1,908
Total Large Commercial	8,903	9,128	9,595	10,086	10,601

APPENDIX E: GROSS CONSUMPTION, IMPORTS AND EXPORTS

Figure 16 shows the gross consumption by customer type. Gross consumption is the total annual consumption by representative agent and includes both own generation and imports from the network.

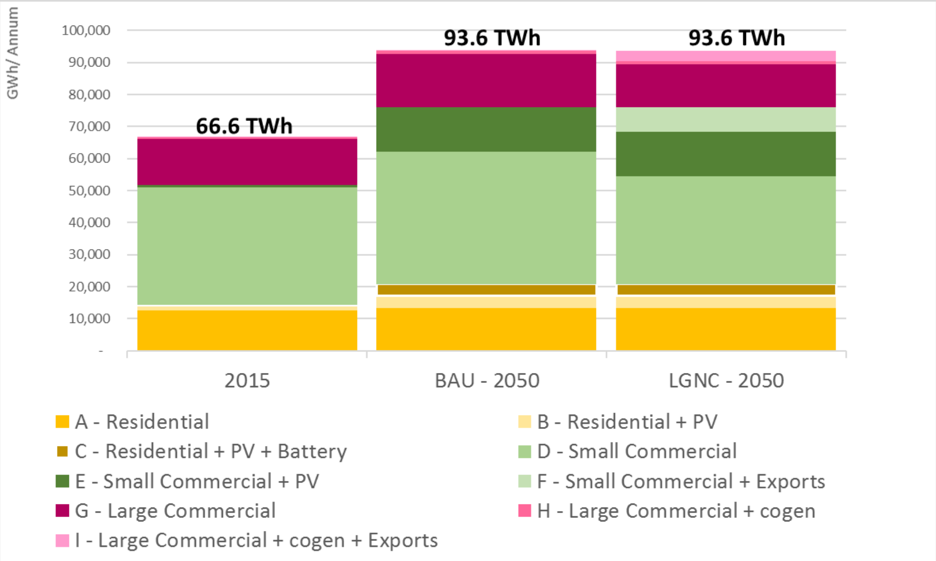


Figure 16: Gross consumption

Figure 17: Net imports

and Figure 17 show imports from the network and exports to the network. Net imports are the imports received by each representative agent to meet gross consumption. Net imports have a direct impact on local distribution networks for meeting demand.

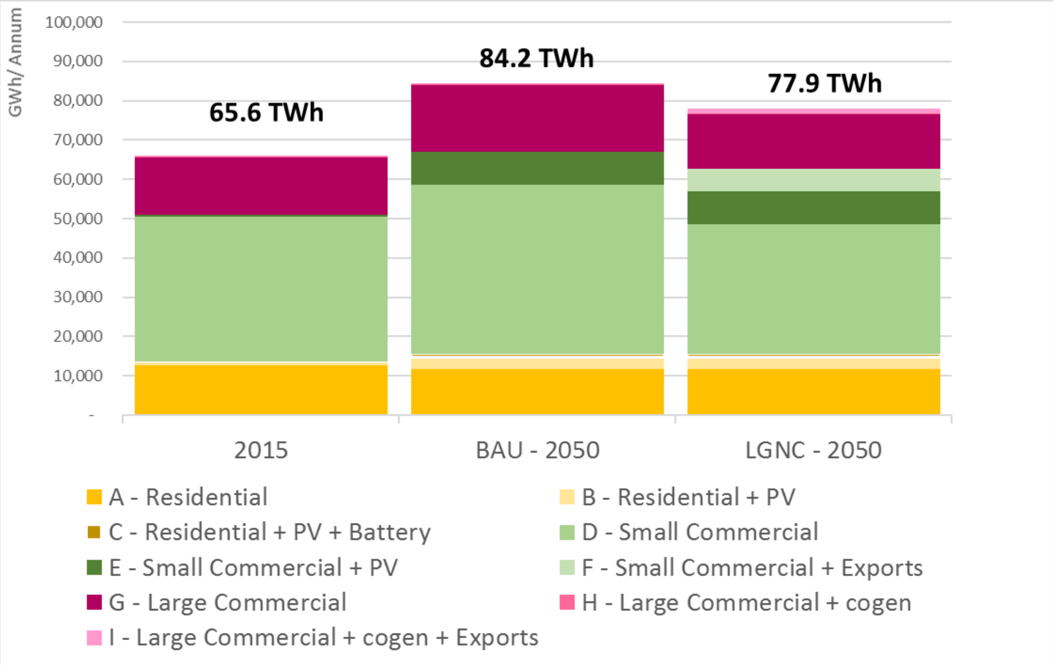


Figure 17: Net imports

Net exports are the exports that are made to the network after own demand requirements have been met.

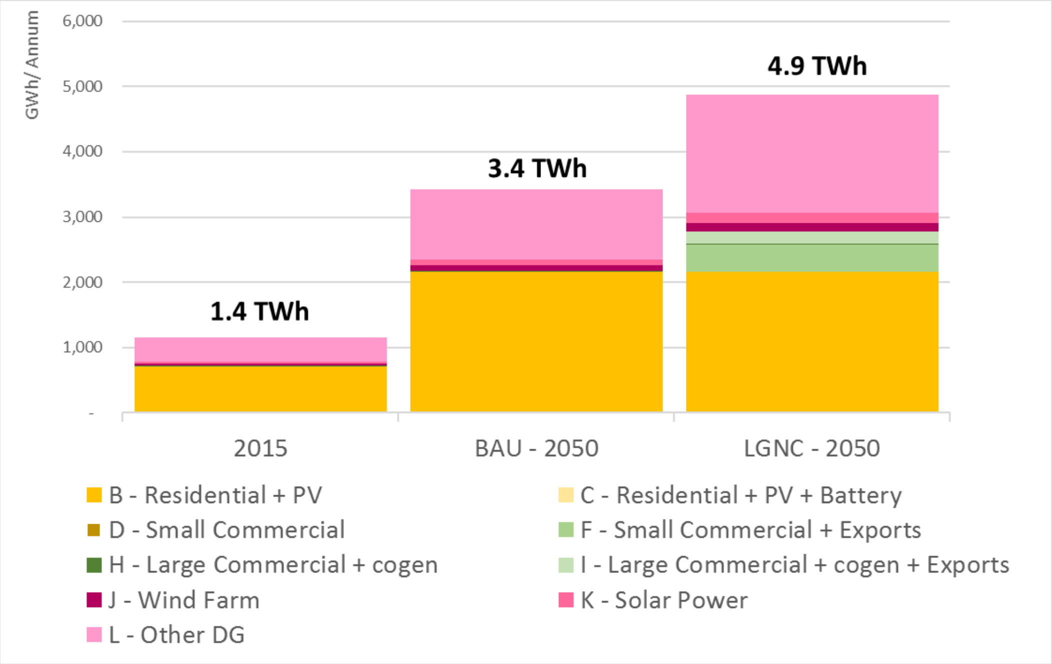


Figure 17: Net exports

APPENDIX F: AGENT PROFILES

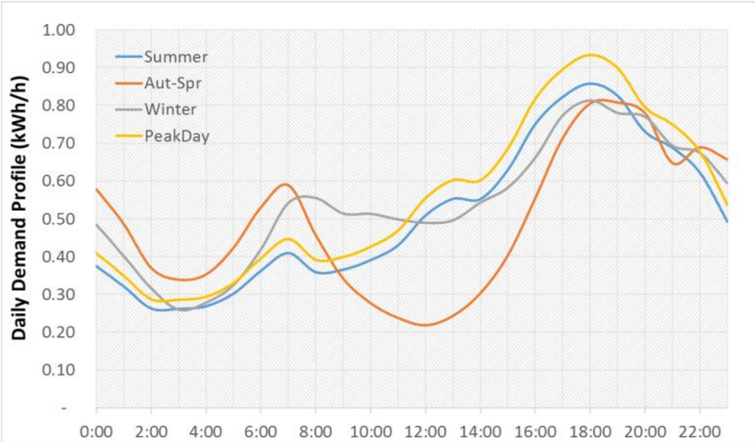


Figure 18: Residential agent

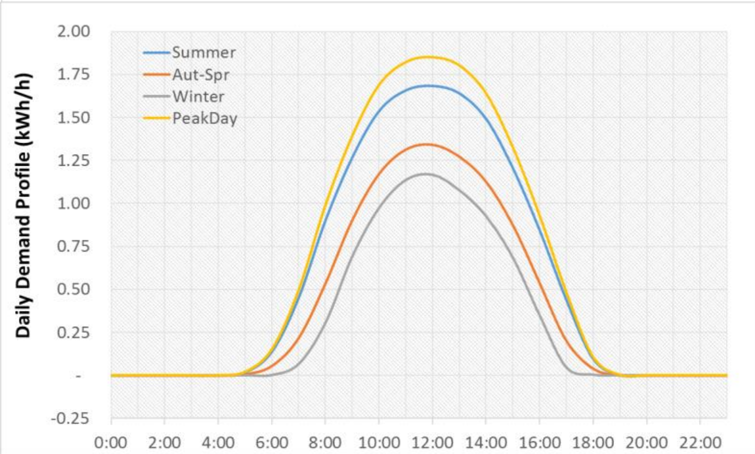


Figure 19: Residential solar PV profile

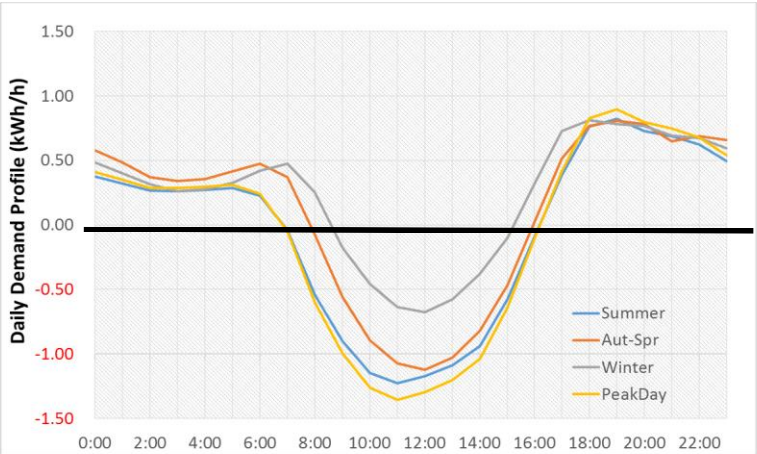


Figure 20: Residential demand with solar PV

Exported electricity below zero

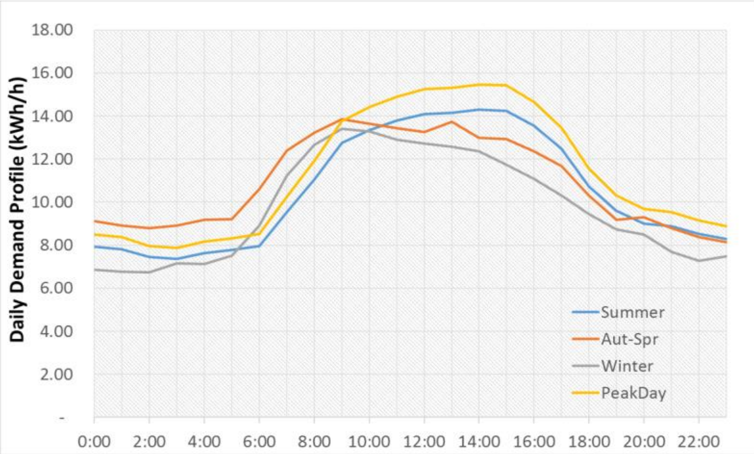


Figure 21: Small commercial demand profile

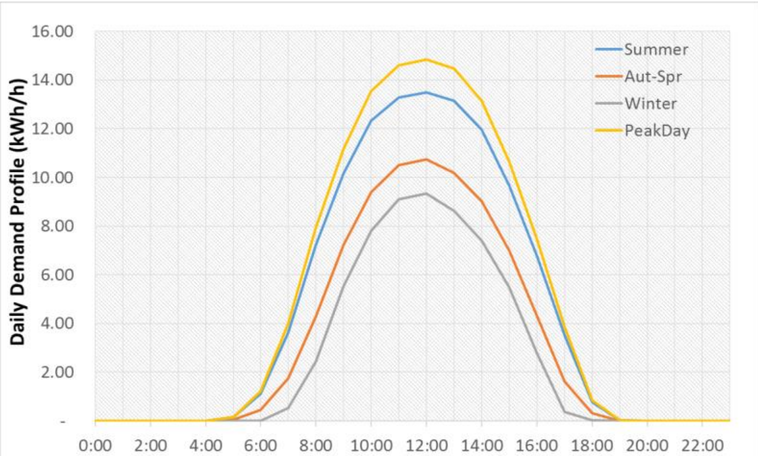


Figure 22: Small commercial solar profiles

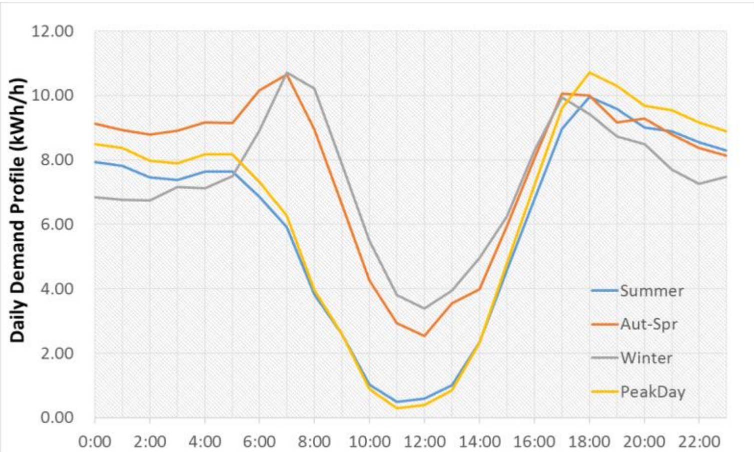


Figure 23: Small commercial plus PV demand profile

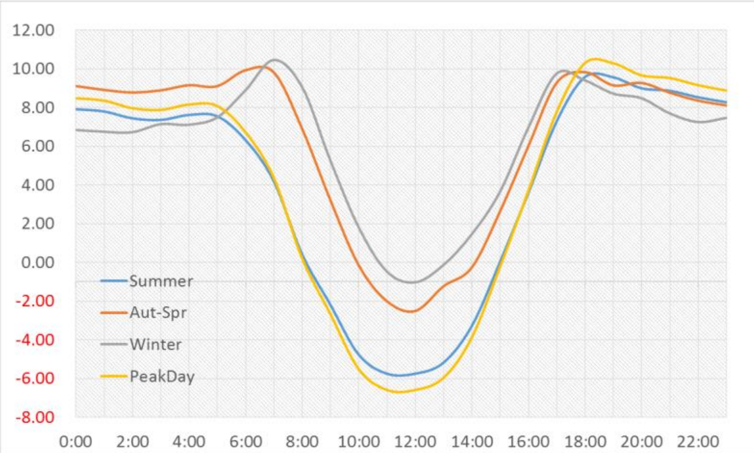


Figure 24: Small commercial with PV + export

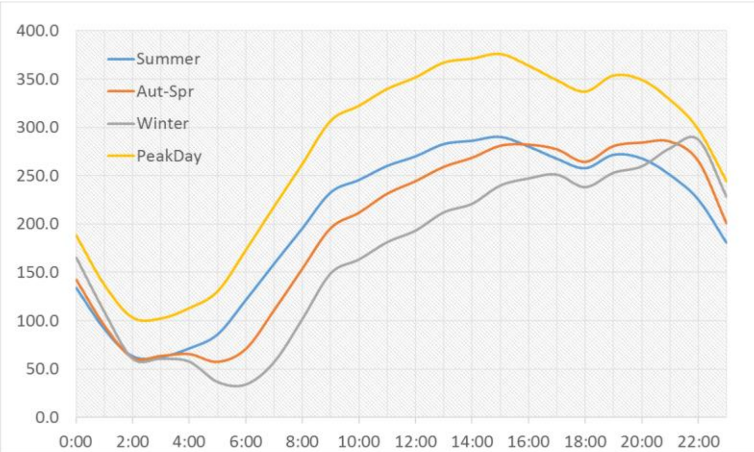


Figure 25: Large commercial demand profile

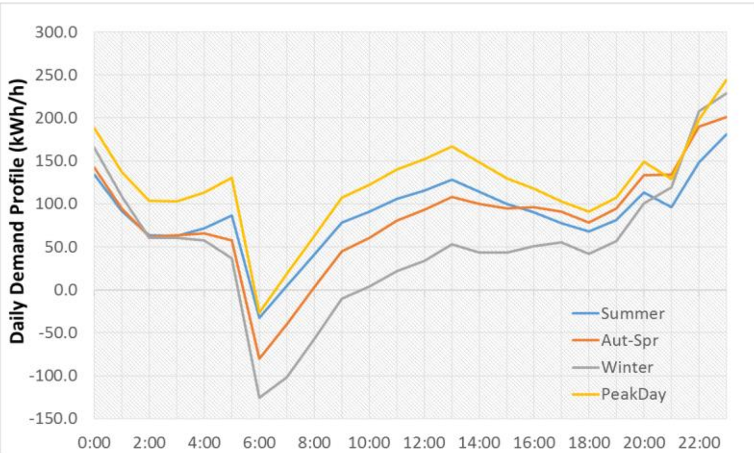


Figure 26: Large commercial with cogen (sized to 60% of peak demand)

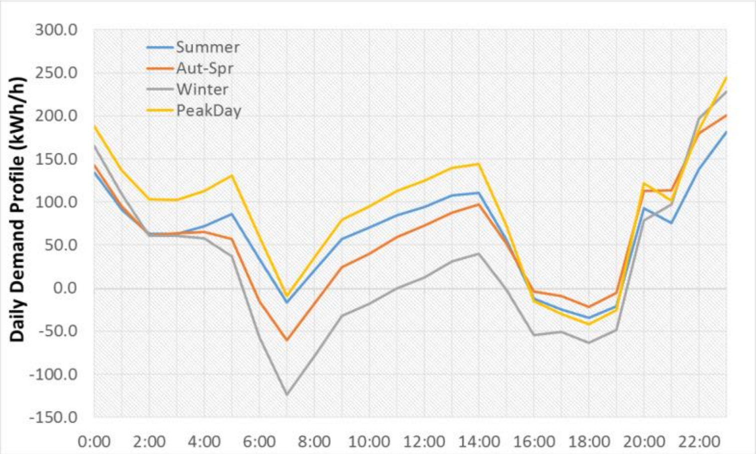


Figure 27: Large commercial agents sized to export 8% total electricity generated

UTS:ISF
INSTITUTE FOR SUSTAINABLE FUTURES