Post-Model Adjustments for Terminal Station Forecasts

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DISCLAIMER

This report has been prepared for the Centre of International Economics (CIE) as an input into their report to Citipower and Powercor ('the Businesses') regarding terminal station demand forecasts for the forthcoming regulatory control period.

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Table of CONTENTS

Table of FIGURES

Table of TABLES

1. Background and objective

Oakley Greenwood (OGW) has been engaged to undertake a metadata analysis of the potential impact of the following five decentralised technologies on the forecast peak demands of the terminal stations serving the Citipower and Powercor ('the Businesses') networks:

- Rooftop solar PV;
- Electric vehicles;
- Battery storage;
- Other forms of distributed generation (excluding PV); and
- Energy efficiency.

This report is provided as an input to a demand forecast that the Centre of International Economics (CIE) has been commissioned to produce at the terminal station level for the Businesses' distribution networks.

2. Caveats

First and foremost, it should be noted that OGW has not been engaged to develop forecasts based on first principles, for example via the development of payback/economic models. Rather, these forecasts are to be based on a metadata analysis, with this focused on the most up-to-date information/forecasts available in the industry. Whilst OGW has used its professional judgement to make a high-level assessment of the reasonableness of various forecasts available in the public domain, it does not warrant any forecasts made by the other parties mentioned in the body of this report.

Secondly, the forecasts assume that each of the terminal stations serving the Businesses will peak between 4pm and 4.30pm in Summer. The model that supports the development of these forecasts can cater for alternative peak demand timing assumptions.

3. Structure of the remaining sections of this Report

The remaining sections of this report are structured as follows:

- Section 4 provides an overview of the methodology we have used to allocate the statewide forecasts of each technology to the Businesses' terminal stations,
- Section 5 discusses the solar PV forecast,
- Section 6 discusses the electric vehicle forecast,
- Section 7 discusses the battery storage forecast,
- Section 8 discusses the energy efficiency forecast,
- Section 9 discusses the large-scale solar forecast;
- Section 10 discusses the impact of known, committed embedded generation projects; and
- Section 11 summarises the impact of each of the aforementioned disruptive technologies at each of the terminal stations serving the Businesses.

4. Overarching methodology

Our step-wise approach to forecasting the impact of each of the technologies analysed in this report, at each of the terminal stations supplying electricity to the Businesses, is as follows:

- From the literature, we have developed a forecast of installed capacity (or number of units, depending on the technology) at a statewide level. We have predominately relied upon the "moderate" case outlined in AEMO's *2018 Electricity Statement of Opportunities* report as the basis for our analysis in this report;
- Except for one technology (large-scale solar), the User can nominate in the model the proportion of that statewide forecast that is allocated to each customer segment (e.g., 70% residential, 30% commercial). For this report, we have based this allocation on:
  - The split identified either qualitatively or quantitatively in the underlying source documentation (e.g., if AEMO has forecast that 70% of new PV will be on residential rooftops, we have, in the model, allocated 70% of forecast PV to residential customers); or,
  - Where the above is not available, we have used our own judgement as to the likely driver/s of that forecast.
- Except for one technology (again, large-scale solar), we have then allocated each of the residential and commercial allocations (from the step above) to **LGAs** based on discrete allocators such as average income levels in that LGA (as compared to other LGAs), the proportion of existing residential households in that LGA, the proportion of existing commercial households in that LGA, or the proportion of forecast new residential households (the full list of allocators is contained in Appendix A). These discrete allocators are designed to reflect the underlying drivers affecting take-up, which again, is based on either:
  - What has been identified (either qualitatively or quantitatively) in the underlying source documentation; or
  - Where the above is not available, our own judgement as to the likely driver/s of that forecast.
- For large-scale solar, we have allocated the statewide forecast to different LGAs based on the types of conditions that are likely to be (a) conducive to the economic installation of that technology and (b) whether a particular LGA is likely to exhibit that condition (e.g., the model allocates AEMO's large-scale solar forecast to the LGAs that we have nominated as having "high" solar irradiance);
- We then map the outcomes of the above (which are at the LGA level) to the terminal stations serving the Businesses' customers based on mapping approved by Citipower/Powercor (see Appendix B for this mapping); and
- We then apply capacity / utilisation factors to each technology's forecast installed capacity in each year at that terminal station (or the number of units, in the case of electric vehicles) to estimate the impact that each technology will have on peak demand at that terminal station. The model allows the User to nominate different peak demand times/seasons for different terminal stations, with this flowing through to the capacity factor/utilisation factor that is used to determine that technology's impact on that terminal station (e.g., the forecast impact of PV at a terminal station will depend on the peak demand time/season that the User has nominated for terminal station).

5. Solar PV

The following table summarises the statewide forecast of solar PV that OGW has reflected in its modelling[1].

Table 1: Statewide forecast of installed solar PV capacity (MW)

Installed capacity	2019	2020	2021	2022	2023	2024	2025	Source
AEMO forecast (ex 100kW-30MW)	2305.13	2670.09	2722.86	2777.11	2832.90	2890.33	2949.40	AEMO - ESOO (ex 100KW-30MW)
Solar Homes Package	48	48	48	48	48	48	48	Estimated impact of Solar Homes Package
Labour Govt Solar Program	194.00	526.70	574.81	624.27	675.12	727.48	781.33	Incremental Impact of Labour Government's Election Commitment
TOTAL	**2547.13**	**3244.79**	**3345.67**	**3449.38**	**3556.02**	**3665.81**	**3778.73**	

As indicated above, we have relied heavily on the most recent AEMO forecasts of solar PV, being those from AEMO's *2018 Electricity Statement of Opportunities* (ESOO). This was released in August 2018[2]. This in turn was based on work undertaken by the CSIRO[3].

We believe this forecast is the most appropriate forecast to use at this time as:

- It is the most up-to-date forecast;
- The CSIRO is, to our mind, a credible independent provider of such a forecast, and
- CSIRO's documented approach to developing their forecasts is, based on our high-level review of their documentation, reasonable.

1 At the time of preparing our last report (5 years ago) for the Businesses, we used ACIL Tasman's forecasts of PV installation (for the RET Review Modelling Market Modelling Of Various Ret Policy Options'), which at a national level, averaged around a 700MW increase in capacity per annum. The year-on-year difference in AEMO's current NEM-wide forecasts is well above this figure, particularly early in the forecast horizon, hence our new forecasts are significantly above the forecasts that underpinned our analysis 5 years ago.

2 AEMO, *2018 Statement of Opportunities*, August 2018.

3 Graham P.W., Wang D., Braslavsky, J., and Reedman L.J. 2018. *Projections for small-scale embedded technologies, Report for AEMO*, CSIRO, Australia.

Notwithstanding the above, we have augmented this forecast to reflect the potential increase in PV installations that may stem from the Victorian State Government's Solar Homes Package[4] as well the labour Government's election commitment to provide interest-free loans for the installation of solar panels by 650,000 eligible customers. Due to the timing of these announcements, these would not have been included in the CSIRO's forecasts that were relied upon by AEMO to inform their *2018 ESOO*. The Solar Homes Package is estimated to add 48MW of installed capacity in 2019, as compared to what is assumed to be installed under AEMO's ESOO forecast.

This is based on the following assumptions:

- There are 24,000 eligible properties;[5]
- We have assumed that only 50% of those properties would have not otherwise been included in AEMO's underlying forecasts[6];
- We have assumed each property installs a 4kW installation; and
- We have assumed that each of these incremental systems is installed in 2019, as the program runs from the 19 August 2018 to 30 June 2019.

Regarding the Labour Government's election commitment to provide an estimated 650,000 eligible customers with zero interest loans with a four-year payback, which would come into effect from July 1 2019, we have assumed given the longer-term duration of the scheme that customers who are already forecast to take-up solar, will now do so via the Labour Government's package. Hence, only the incremental difference between the Governments' package (650,000 eligible customers) and AEMO's original forecast has been added to AEMO's original forecast. Clearly, this is somewhat conservative, and the incrementality may in fact exceed this level.

We have aligned the take-up so as to commence in 2019, as per the start of the program.

The following table describes the allocation factors that we used to allocate the statewide forecast of solar PV uptake – from the table above – to each of the terminal stations serving the Businesses.

Table 2: Allocators adopted for solar PV

Driver of forecast	Allocator	Percentage split - starting	Allocator	Percentage split - incremental
Residential Existing	Prop_SolarCap	100%	Prop_Exist_Res_Cust	35%

4 https://www.solar.vic.gov.au/ [accessed 19 Sep 2018].

"Eligible households can claim a 50 per cent rebate on the cost of a solar PV system, up to a maximum rebate of $2,225 or a $1,000 rebate for the replacement of hot water systems with solar hot water. Households will only be eligible for one rebate under the Solar Homes package (i.e. a household that accesses a solar hot water rebate cannot claim a solar PV rebate)."

5 https://www.solar.vic.gov.au/Solar-Panel-Rebate.

6 This reflects the fact that it is difficult, *ex ante*, to estimate the *incremental* impact of such a rebate program. For example, at one end of the spectrum, all 24,000 customers may never have considered installing a PV system, hence, from a modelling perspective, the full 24,000 customers could be considered *incremental* to the underlying AEMO forecasts. At the other end of the spectrum, it could be that this program simply makes it cheaper for those customers who were already planning to install a PV system between now and mid 2019 (when the rebate program ceases). It could also simply bring forward customers' decisions to install PV, hence not changing longer-term installation levels. For the lack of a better estimate, we have assumed that 50% of the installations are incremental, with this partly reflecting the short-term duration of the scheme and the fact that it wasn't linked to the election outcome.

Residential New	Prop_New_Res_Cust	0%	Prop_New_Res_Cust	41%
Commercial - Existing	Prop_Exist_Com_Cust	0%	Prop_Exist_Com_Cust	12%
Commercial - New	Prop_New_Com_Cust	0%	Prop_New_Com_Cust	12%

To summarise, existing PV capacity is split out based on the existing proportion of solar in each LGA (this is based on up-to-date figures from the Clean Energy Regulator). New, incremental PV is assumed to be predominately taken up by new residential customers (41%), and then existing residential customers (35%), with the remaining 24% split between new and existing commercial customers.

The rationale for adopting these allocators for new PV are as follows:

- The 24% allocation to commercial customers (and hence the 76% allocation to residential customers) reflects AEMO's forecast (in the *2018 ESOO*) of the incremental contribution each segment is expected to make to overall installed capacity between 2019 and 2030; and
- When discussing trends in effective residential rooftop solar capacity by state/territory, the CSIRO state[7] that the "*difference in the scale and rate of growth in states/territories largely reflects the differences in current population and future customer growth*". It follows on by stating that "*Queensland is expected to remain the state with the highest absolute residential rooftop solar capacity reflecting both higher customer growth and a favourable solar capacity factor. Western Australia is assumed to have the highest customer growth and also experiences the highest rate of growth in effective residential rooftop solar capacity*". From this, we have deduced that customer growth is a key driver of CSIRO's forecast of PV installations, hence our relatively high allocation of 41%.

The following table outlines the capacity factors that we have adopted over the period when the Businesses' terminal stations generally peak. These are based on previous OGW analysis.

Table 3: Capacity factors for solar PV during mid/late afternoon and early evening

Season	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 19:00
Summer	51%	45%	37%	29%	19%	10%	6%	4%
Winter	26%	19%	11%	5%	1%	1%	2%	1%

6. Electric vehicles

The following table summarises the Statewide forecast of Electric Vehicles (EVs) that OGW has reflected in its modelling.

7 Graham P.W., Wang D., Braslavsky, J., and Reedman L.J. 2018. *Projections for small-scale embedded technologies, Report for AEMO*, CSIRO, Australia, page 35.

Table 4: Statewide forecasts of the number of Electric Vehicles

Electric vehicles	2019	2020	2021	2022	2023	2024	2025	Source
EV numbers ('000s)	2.86	4.17	7.71	13.81	24.12	41.21	66.75	AEMO - ESOO

We have relied heavily on the most recent AEMO forecasts of EV for Victoria from the *2018 ESOO*. This was released in August 2018. This in turn was based on work undertaken by the CSIRO.

We believe that AEMO's ESOO forecast is the most appropriate forecast to use at this time as:

- It is the most up-to-date forecast;
- The CSIRO, which derived the underlying forecast, is to our mind, a credible independent provider of such a forecast, and
- CSIRO's documented approach to developing their forecasts is, based on our high level review of their documentation, reasonable.

The following table outlines how we have allocated the statewide EV forecasts

Table 5: Allocators adopted for EVs

Driver of forecast	Allocator	Percentage split - starting	Allocator	Percentage split - incremental
Residential	Prop_HH_Income	34%	Prop_HH_Income	70%
Commercial - Fleet	Prop_Exist_Com_Cust	66%	Prop_Exist_Com_Cust	30%

To summarise, existing EV capacity is split out based on an estimate of the existing proportion of EVs attributable to residential versus business customers. This has been sourced from a report from the Electric Vehicle Council[8].

New, incremental EV is predominately allocated to new residential customers (70%), with this then allocated to LGAs based on their relative median incomes, with the remainder allocated to existing commercial customers (30%), with these then allocated to LGAs based on the overall proportion of commercial customers in that LGA.

The rationale for adopting these allocators is as follows:

- The 70/30 split of future EV take-up between residential and commercial customers is intended to reflect the qualitative findings from the Electric Vehicle Council's report quoted earlier, which indicated that "*fleet is likely to reduce relative to existing levels*". Unfortunately, it does not forecast a percentage, nor were we able to identify any definitive discussion of this in the CSIRO report, hence we have adopted a simple 70/30 estimate; and

8 Electric Vehicle Council, "*The state of electric vehicles in Australia - Second Report: Driving Momentum In Electric Mobility*", June 2018, page 7.

- The CSIRO mention factors such as education level attained, share of ages (with middle-age bands receiving highest scores) and a number of other socio-economic factors[9]. We have used median income as a proxy for these socio-economic factors. In saying this, we note that income also aligns with the outcomes of a number of other studies looking into the drivers of EV take-up. For example, OFGEM found that[10]:

  "EV owners will have access to a wider range of energy products and services than non-EV owners. Under current charging arrangements, the costs and benefits of the EV transition will be unequally distributed across consumers, with lower income households likely to be paying a disproportionate share of the costs. The Index of Multiple Deprivation (IMD) provides a measurement of deprivation across England. To date, EV uptake and chargepoint installation has been significantly lower in areas that are more deprived (Fig. 13). The least deprived decile accounts for more EV chargepoints than any other decile, with the mean EV user in the 7th decile, and the median in the 8th decile - a strong indicator that current uptake is heavily linked to socio-demographic influences."

The following table outlines the capacity factors that we have adopted over the period of the day when the Businesses' terminal stations generally peak. Two options are presented – "Continued Pricing Structure" and "Cost Reflective Pricing Structure". The underlying driver of the difference in the outcomes under the two options is that with cost reflective prices consumers will be incentivised to move their EV charging away from the afternoon / early evening period, when electricity networks are more likely to be constrained and hence higher prices prevail. Our modelling assumes a continuation of the existing price structure, and hence, it incentivises customers to charge their EV when it is convenient (the red curve in AEMO's graph below), even if this is not the most economically efficient outcome.

Table 6: kW charge per vehicle

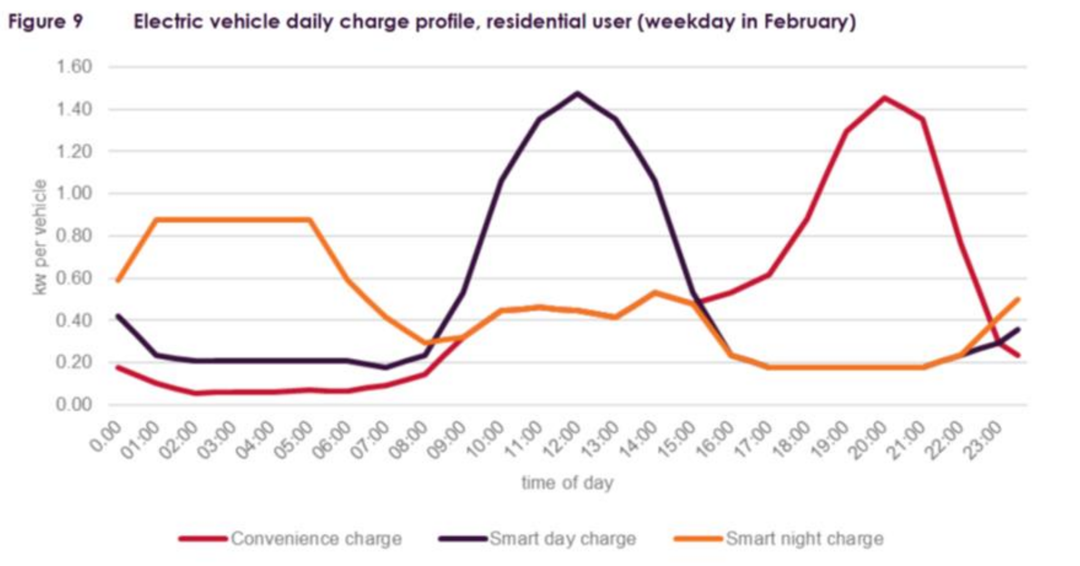
Price structure	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 19:00	19:00 - 19:30
Continued Pricing Structure	0.50	0.55	0.60	0.70	0.80	0.90	1.00	1.20
Cost Reflective Pricing Structure	0.50	0.20	0.20	0.20	0.20	0.20	0.20	0.20

These 'kW charge per vehicle' figures are based on Figure 9 of AEMO's *2018 ESOO*. This has been reproduced below.

9 Graham P.W., Wang D., Braslavsky, J., and Reedman L.J. 2018. *Projections for small-scale embedded technologies, Report for AEMO*, CSIRO, Australia, page 14.

10 OFGEM, *Implications of the transition to Electric Vehicles,* Page 30.

Figure 1: Electric vehicle daily charge profile



Source: AEMO, *2018 Electricity Statement of Opportunities*, page 32

7. Beyond-the-meter battery storage

The following table summarises the statewide forecast of beyond-the-meter battery capacity that OGW has reflected in its modelling.

Table 7: Statewide forecast of beyond-the-meter battery capacity (MW)

Battery capacity	2019	2020	2021	2022	2023	2024	2025	Source
MW	44.5	73.84	82.96	90.25	103.36	125.77	155.02	AEMO - ESOO

As indicated above, we have relied heavily on the most recent AEMO forecasts of battery installations from the *2018 ESOO*.

For similar reasons to those outlined in relation to solar PV, we believe this forecast is the most appropriate forecast to use at this time.

The following table describes the allocation factors that we used to allocate the statewide forecast of battery uptake – from the table above – to each of the terminal stations serving the Businesses.

Table 8: Allocators adopted for battery

Customer segments	Allocator	Percentage split - starting	Allocator	Percentage split - incremental
Residential	Prop_HH_Income	95%	Prop_HH_Income	94%
Commercial	Prop_Exist_Com_Cust	5%	Prop_Exist_Com_Cust	6%

To summarise, existing battery capacity is allocated almost entirely to residential customers, with this then allocated to LGAs based on the average income within each LGA. A small proportion (5%) of existing battery capacity is allocated to existing commercial customers, with this based on the proportion of existing commercial customers in each LGA. This overall split (95/5) is informed by AEMO's allocation of existing capacity to those two customer segments.

New, incremental battery installations are allocated between residential and commercial customers using percentages derived from the underlying AEMO forecasts. These are almost exactly the same as the current splits. The same allocators have been used.

The rationale for utilising these allocators is as follows:

- For residential customers, income was considered a primary factor, as batteries require a large upfront capital expenditure. As a result, we linked the allocation of residential battery installation to the average median income within an LGA; and
- For commercial customers, we allocated the forecast take-up based on the existing proportion of commercial customers in an LGA, relative to the entire state.

The following table outlines the capacity factors that we have adopted for the late afternoon/early evening period when the Businesses' terminal stations are likely to peak.

Table 9: Capacity factors for beyond-the-meter batteries

Proportion of the battery 's capacity discharged	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 19:00
Summer	1.0%	1.0%	1.0%	1.0%	1.0%	4.0%	4.0%	1.0%
Winter	0%	0%	0%	0%	0%	0%	0%	0%

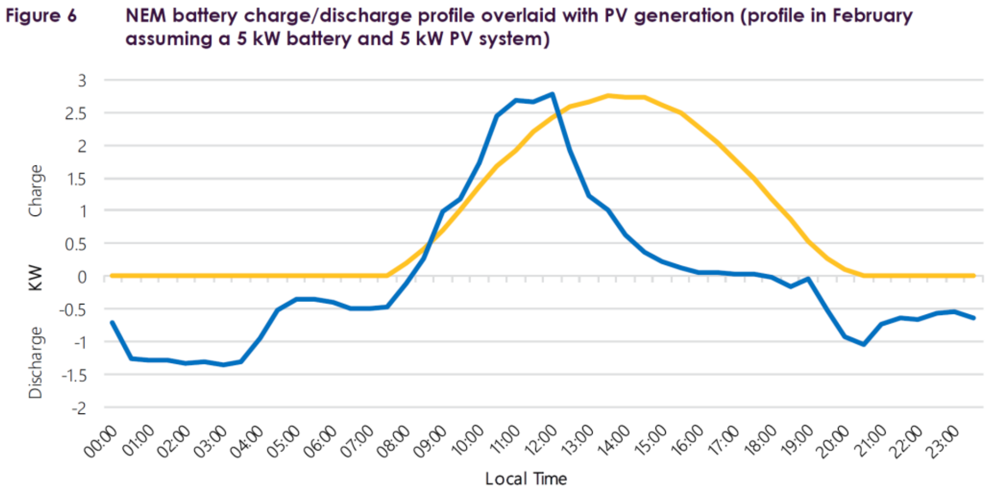
The above reflects the proportion of the installed battery capacity that is assumed to be discharged in each half hour period. It assumes that cost-reflective prices signals **are not** adopted for either energy consumption or energy exported, hence customers are not financially incentivised to maximise the overall economic value of their installed capacity (i.e., they are not incentivised to discharge from their battery during times of system peak demand)[11].

The percentages are quite low as CSIRO's analysis indicates that on late summer afternoons, a customers' battery is likely to be already fully charged as a result of their PV system's excess (as compared to their underlying demand) production in the mid-afternoon, yet they are still able to predominately rely on the production from their PV system through to early evening, hence they do not need to discharge their battery to meet their own requirements.

The above proportions have been derived from the following figure, which is from AEMO's *2018 ESOO* and which reflects the kW discharged/charge per battery. We have converted this kW discharged/charge per battery to a proportion of installed capacity charged/discharged.

11 It should be noted that for the purposes of developing our last report (5 years ago), we assumed that there would be price signals to incentivise customers to discharge their batteries when the system peaks (as this is consistent with economic theory and was aligned to the then recent Rule change that required businesses to move to cost-reflective prices). Our changed assumption is based on our current view of the likelihood of tariff reform. This changed assumption materially impacts upon the contribution batteries make to reductions in peak demand.

Figure 2: NEM battery charge/discharge profile



Source: AEMO, *2018 Electricity Statement of Opportunities*, page 29.

8. Energy efficiency

The following table summarises the statewide forecast of the GWh reduction impact of energy efficiency that OGW has reflected in its modelling. This gets converted into a MW reduction figure in the underlying model.

Table 10: Statewide forecast of energy efficiency (GWh)

Energy efficiency	2019	2020	2021	2022	2023	2024	2025	Source
GWh	150.49	380.41	703.18	1056.44	1278.60	1552.36	1830.20	AEMO - NEFR 24 Aug 2018

As noted, these figures are taken from the most recent update to AEMO's *2018 National Electricity Forecasting Report* (NEFR), which was published on 24 August 2018. This is the most recent and therefore the most appropriate forecast to use.

However, the NEFR database does not translate this annual forecast of the impact of energy efficiency measures on energy throughput into its annual impact on peak demand. A report by Strategy, Policy, Research commissioned by AEMO[12] does provide information on Australia-wide peak demand impact of energy efficiency. In a conversation, the author of that study said that annual, state-by-state demand impacts had been calculated. A request was made on our behalf to AEMO for that data, but no response was received from AEMO.

12 Strategy, Policy, Research, *Energy Efficiency Impacts on Electricity and Gas Demand to 2037-38: Final Report*, 1 June 2018.

An alternative discussed with the author of the Strategy, Policy, Research report was pursued instead. This approach employed the use of Conservation Load Factors (CLFs) to calculate the peak demand impact associated with the annual energy efficiency impacts provided in the 24 August 2018 update to the NEFR. This is done using the following formula:

$$\text{Peak demand reduction}^{i}_{\text{Summer, Winter}} = \frac{\dfrac{\text{Annual energy usage reduction}^{i}_{\text{jurisdiction}}}{8{,}760\text{ h}}}{\text{CLF}^{i}_{\text{Summer, Winter}}}$$

The CLFs used in the calculation were taken from a 2015 report by Jacobs that was commissioned by the Victorian Department of Economic Development, Jobs, Transport and Resources as part of its assessment of the impacts of the Victorian Energy Efficiency Target (VEET)[13]. These are the most recently published CLFs available in the literature and were used in a study that was specifically focused on the peak demand impact of energy efficiency measures in Victoria[14]. These CLF's assume a summer peak, between 4pm and 4.30pm.

The peak demand impacts of the annual energy efficiency impacts (in GWh) provided in the NEFR Annual Consumption dataset of 24 August 2018 for Victoria for the years 2019 through 2025 inclusive were then calculated through the following steps:

- Calculate the load-weighted average CLF for the residential and business sectors, based on the results of the VEET in 2016, as published by the Victorian Essential Services Commission[15].
- Apply those CLFs to the annual residential and business energy efficiency impacts provided in the NEFR Annual Consumption dataset.

The table below shows the results of those calculations.

Table 11: Impact of EE in GWh and CLFs by customer segment

Year	Residential			Business			Total	
	GWh EE	CLF	MW	GWh EE	CLF	MW	GWh EE	MW
2019	136.6	2.48	6.3	13.9	0.7	2.3	150.5	8.5
2020	325.1	2.48	15.0	55.3	0.7	9.0	380.4	24.0
2021	532.9	2.48	24.5	170.3	0.7	27.8	703.2	52.3
2022	707.4	2.48	32.5	349.1	0.7	56.9	1056.4	89.5

13 Jacobs Group (Australia) Pty Ltd, *Energy Market Impact of the VEET Scheme*, April 2015.

14 The use of these CLFs was recommended by the author of the Strategy, Policy, Research study. The CLFs in that were taken from two studies published in 2010 and 2011 for the Commonwealth and NSW governments.

15 Essential Services Commission, *VEET Performance Report 2016*, August 2017. This entailed conversion of the Victorian Energy Efficiency Credits, which are the units in which the VEET is measured and are denominated in tonnes of carbon, to their GWh equivalent. This was done with reference to the average emissions intensity of the Victorian generation fleet as published by AEMO.

2023	839.5	2.48	38.6	439.1	0.7	71.6	1278.6	110.2
2024	1024.3	2.48	47.1	528.1	0.7	86.1	1552.4	133.2
2025	1212.1	2.48	55.8	618.1	0.7	100.8	1830.2	156.6

Source: OGW analysis

The following table describes the allocation factors that we used to allocate the statewide forecast of EE – from the table above – to each of the terminal stations serving the Businesses.

Table 12: Allocators adopted for EE

Customer segments	Allocator	Percentage split - starting	Allocator	Percentage split - incremental
Residential Existing	Prop_Exist_Res_Cust	37%	Prop_Exist_Res_Cust	37%
Commercial - Existing	Prop_Exist_Res_Cust	63%	Prop_Exist_Com_Cust	63%

We have allocated these forecasts between residential and non-residential customers based on the proportionate contribution each segment makes to MW reductions over the period 2019-2029. These then get allocated to LGAs based on the existing proportion of each customer segment in that LGA.

The following table outlines the CLFs that we have adopted for the late afternoon/early evening period when the Businesses' terminal stations are likely to peak.

Table 13: CLFs for EE

CLFs	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 19:00
Weighed CLF	1.36	1.36	1.36	1.36	1.36	1.36	1.36	1.36

This is based on the weighting the CLF figures outlined in table 8, by the overall expected MWs saved by each customer segment over the evaluation period. Again, to reiterate, they are based on a summer peak at 4 – 4.30pm. Therefore, strictly speaking, these CLF's may change over the hours covered in the table above, however, we have little empirical information to justify any adjustment.

9. Large scale solar

The following table summarises the statewide forecast of large-scale solar PV that OGW has reflected in its modelling.

Table 14: Statewide forecast of large-scale solar PV (MW)

Installed capacity	2019	2020	2021	2022	2023	2024	2025	Source
Large scale solar	87.19	91.28	94.91	98.16	111.95	125.04	137.95	AEMO - ESOO (100KW-30MW)

As indicated above, we have relied heavily on the most recent AEMO forecasts of solar PV (which includes systems between 100kW and 30MW), from the *2018 ESOO*.

We believe this forecast is the most appropriate forecast to use at this time for the reasons outlined earlier in our report.

For completeness, it is noted that we have not made any allowance in the statewide forecast for the recently announced results of the State Government's reverse auction to support its Victorian Renewable Energy Target (VRET). It is assumed that these will be connected at transmission level, not distribution.

The following table describes the allocation factors that we used to allocate the statewide forecast of large-scale solar PV - from the table above - to each of the terminal stations serving the Businesses.

Table 15: Allocators adopted for large-scale solar PV

Driver of forecast	Allocator	Percentage split - starting	Allocator	Percentage split - incremental
Unknown location	Prop_High_Solar_Resource	100%	Prop_High_Solar_Resource	100%

To summarise, we are assuming that AEMO's large-scale solar forecasts will be located evenly across the areas that we have nominated (in the model) as being "High Solar Resource areas".

We have identified 12 LGAs that are likely to be considered high solar resource areas. These are almost exclusively in the north western part of the state and are outlined in the table below.

Table 16: High solar resource areas

High Solar Resource LGAs				
Buloke Shire Council	Campaspe Shire Council	Gannawarra Shire Council	Hindmarsh Shire Council	Horsham Rural City Council
Loddon Shire Council	Mildura Rural City Council	Northern Grampians Shire Council	Pyrenees Shire Council	Swan Hill Rural City Council
West Wimmera Shire Council	Yarriambiack Shire Council			

The nomination of these areas is based on the following information/figures, both of which indicate that the north-western part of Victoria is the area that receives the most solar irradiance/solar farm development.

Figure 3: Annual average solar radiation

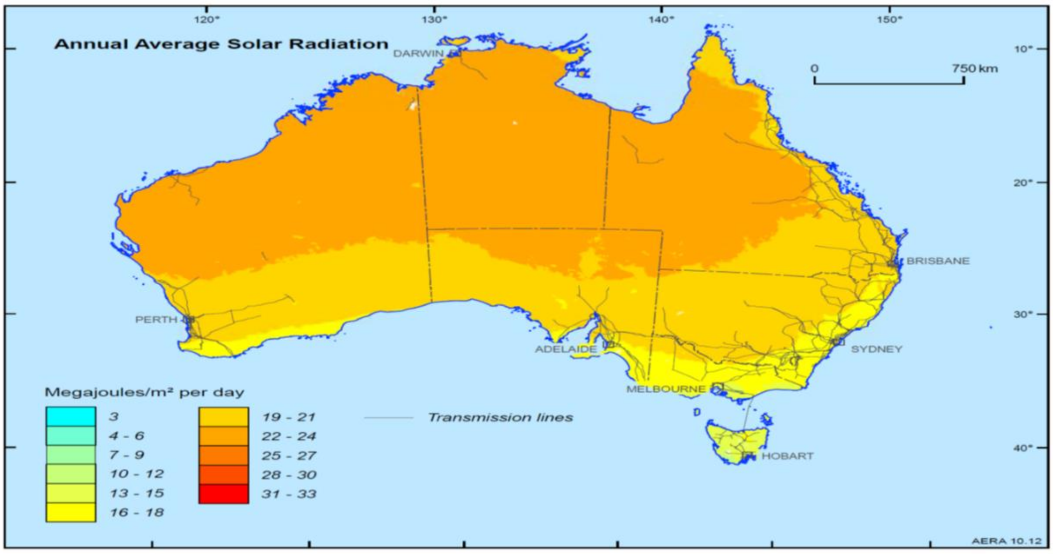
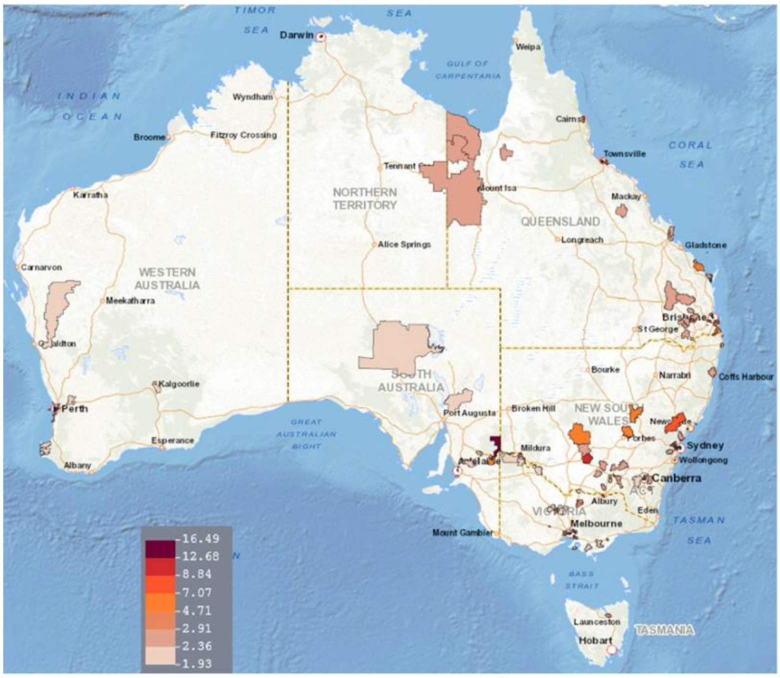


Figure 10.12 Annual average solar radiation

Source: ARENA, *Australian Energy Resource Assessment*, First Edition, Figure 10.1

Figure 4: Map of projected non-schedule solar generation capacity



Apx Figure B.3: Australian map of the projected non-scheduled generation solar capacity (MW) in the 100kW to 1 MW range in 2030 by postcode

Source: Graham P.W., Wang D., Braslavsky, J., and Reedman L.J. 2018*. Projections for small-scale embedded technologies, Report for AEMO*, CSIRO, Australia, page 62.

We have adopted a capacity factor (at the time of peak demand) of 11%. This reflects the assumption AEMO has adopted in its 2018 *Integrated System Plan*[16]. However, given its magnitude, this is likely to reflect a very late afternoon/early evening peak period[17], hence it may not be correct for all terminal stations (if they peak earlier).

10. Already committed generation

The Businesses provided us with a list of already-committed projects for inclusion in our modelling. This list is reproduced below.

Table 17: List of committed embedded generation projects

Name	Type	Assumed connection	Size (MW)	Commissioning	Summer	Winter
Mt Gellibrand Wind Farm*	Wind	MLTS_GTS_PTH	66	Q3 2018	8.10%	7.30%
Mt Gellibrand Wind Farm*	Wind	HYTS_TGTS_APD	66	Q3 2018	8.10%	7.30%
Bannerton Solar Farm	Solar PV	WETS_66kV	88	Q3 2018	11.00%	11.00%
Wemen Solar Farm	Solar PV	WETS_66kV	87.75	Q4 2018	11.00%	11.00%
Yatpool Solar Farm	Solar PV	RCTS_66kV	81	Q4 2018	11.00%	11.00%
Karadoc Solar Farm	Solar PV	RCTS_66kV	90	Q3 2019	11.00%	11.00%
Greenswitch Solar Farm	Solar PV	KGTS_22kV	29.9	Q1 2019	11.00%	11.00%
Yendon Wind Farm	Wind	BATS_ELTS	144.4	Q1 2019	8.10%	7.30%
Edify Battery (at Gannawarra Solar Farm GSF)	Battery	KGTS_66kV	20	Q4 2018	50.00%	50.00%
Numurka Solar Farm (NEOEN)	Solar PV	SHTS_GNTS	100	Q1 2019	11.00%	11.00%
245 Bacchus Marsh Rd Solar	Solar PV	MLTS_GTS_PTH	1.36	Q1 2019	11.00%	11.00%

Source: The Businesses; OGW based on AEMO information; *We have split this development into two to reflect the fact that it is allocated across two connection points.

16 http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database

17 AEMO states in a note in its spreadsheet that: "As solar penetration increases, peak demand moves away from times where solar energy is available".

The capacity factors – which are used to determine the outputs of these committed EGs at the time when terminal stations are expected to peak – are based on information used by AEMO in its *Integrated System Plan*[18]. The wind capacity factors also align with figures reported by AEMO in other documents[19].

We have compared the list of committed projects provided by the Businesses to AEMO's *Integrated System Plan*, in particular, its "*2018 Integrated System Plan Modelling Assumptions*" tab. There do not appear to be any distribution-connected EGs in the Businesses' areas that are missing from the Businesses' list.

11. Summary of impacts

The following is an extract of the results from the underlying model.

Figure 5: Summary of incremental changes in demand

	Incremental Demand Impact per year (MW) - POE 50									
Terminal Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
RCTS_22kV	0.24	0.07	0.08	0.10	0.11	0.12	0.18	0.17	0.20	0.26
RCTS_66kV	0.85	0.26	0.27	0.37	0.39	0.41	0.63	0.61	0.70	0.91
WETS_66kV	1.69	0.63	0.65	1.18	1.24	1.31	1.72	1.79	2.11	2.66
KGTS_22kV	0.06	0.03	0.03	0.08	0.08	0.09	0.10	0.11	0.13	0.16
KGTS_66kV	0.92	0.41	0.42	0.87	0.90	0.95	1.17	1.26	1.50	1.87
HOTS_66kV	1.95	0.96	0.99	2.31	2.40	2.54	3.01	3.32	3.99	4.97
BETS_22kV	0.56	0.14	0.15	0.16	0.17	0.19	0.33	0.32	0.36	0.49
BETS_66kV	7.67	2.06	2.19	2.86	3.12	3.37	5.44	5.39	6.30	8.37
SHTS_GNTS	5.01	1.40	1.51	1.62	1.83	1.98	3.32	3.26	3.80	5.09
HYTS_TGTS_APD	4.44	1.33	1.49	1.37	1.71	1.99	3.39	3.63	4.54	6.26
BATS_ELTS	7.74	1.89	2.04	2.05	2.36	2.60	4.78	4.66	5.48	7.50
MLTS_GTS_PTH	11.51	2.70	2.90	2.60	2.96	3.20	6.29	5.79	6.57	9.03
ATS_West	13.16	2.66	2.82	2.60	2.86	3.03	6.54	5.72	6.29	8.71
ATS_BLTS	2.39	0.56	0.61	0.55	0.64	0.70	1.35	1.27	1.46	2.02
BLTS_22kV	0.74	0.18	0.19	0.17	0.20	0.21	0.41	0.39	0.44	0.61
KTS_East	4.55	1.09	1.16	1.02	1.15	1.23	2.41	2.16	2.41	3.29
KTS_West	13.50	2.78	2.96	2.74	3.06	3.29	6.95	6.22	6.97	9.66
WMTS_66kV	13.36	3.07	3.28	2.91	3.27	3.48	6.97	6.23	6.92	9.48
WMTS_22kV	8.01	1.82	1.93	1.71	1.91	2.02	4.11	3.63	4.00	5.48
BTS_22kV	5.32	1.23	1.31	1.16	1.31	1.40	2.79	2.51	2.80	3.83
FBTS_66kV	8.32	2.08	2.24	1.96	2.24	2.41	4.61	4.25	4.81	6.56
RTS_66kV_Bus1and4	5.88	1.44	1.54	1.36	1.55	1.67	3.22	2.96	3.34	4.56
RTS_66kV_Bus2and3	12.96	3.32	3.57	3.11	3.58	3.86	7.26	6.73	7.64	10.41
RTS_22kV	3.45	0.83	0.89	0.78	0.89	0.95	1.86	1.69	1.90	2.59
SVTS_66kV	1.98	0.53	0.57	0.49	0.57	0.61	1.12	1.04	1.18	1.61
TSTS_66kV	3.97	1.06	1.14	0.98	1.13	1.22	2.25	2.09	2.37	3.21
Spare	-	-	-	-	-	-	-	-	-	-
Spare	-	-	-	-	-	-	-	-	-	-
	140	35	37	37	42	45	82	77	88	120

Other key outputs from the model are provided separately in speadsheet form.

18 http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database....2018 Integrated System Plan Modelling Assumptions (1)

19 AEMO, *South Australian renewable energy report*, November 2017, Table 7 Expected wind contribution during peak demand.

Appendix A: Basis of allocators

The following tables are extracts from the underlying model. They show the allocators that are available for use in the model. Of interest, it is noted that:

- All LGAs in Victoria are considered. This is because we are inputting Statewide forecasts, not forecasts that are at the Business level (which in turn would have allowed us to only include LGAs served by the Businesses, as we would only need to allocate the forecasts across the LGAs served by the Businesses);
- We have relied upon information sourced from the Regional Development Victoria website (http://www.rdv.vic.gov.au/information-portal/table-and-chart) for both current and forecast customer number information at the LGA level. These customer numbers are used as a proxy for the number of *electricity connected customers* by LGA, as electricity distribution businesses do not generally publish this information;
- Existing solar capacity by LGA is sourced from http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations#Summary-of-postcode-data. This provides information up to, and including, June 2018; and
- Median household income data is sourced from the Regional Development Victoria website,http://www.rdv.vic.gov.au/information-portal/table-and-chart, which explicitly states that the median incomes they have reported have been derived from the ABS Census 2016 (Data Pack G02).

LGA	Existing Residential Customers (Occ Dwellings Proxy)	*Prop_Exist_Res_Cust*	Forecast New Residential Customers	*Prop_New_Res_Cust*	Existing Commercial Customers	*Prop_Exist_Com_Cust*	Forecast New Commercial Customers	*Prop_New_Com_Cust*
Alpine (S)	5558.00	0.2479%	-194.00	-0.03234%	1448.00	0.26%	-50.54	-0.03%
Ararat (RC)	4629.00	0.2064%	13.00	0.0021672%	1030.00	0.182%	2.89	0.001910%
Ballarat (C)	40614.00	1.81%	11077.00	1.85%	8011.00	1.41%	2184.91	1.44%
Banyule (C)	46198.00	2.06%	8786.00	1.46%	10319.00	1.82%	1962.48	1.30%
Bass Coast (S)	14353.00	0.64%	4178.00	0.70%	2840.00	0.50%	826.69	0.55%
Baw Baw (S)	18742.00	0.84%	6816.00	1.14%	5098.00	0.90%	1854.02	1.22%
Bayside (C)	36776.00	1.64%	8293.00	1.38%	13036.00	2.30%	2939.62	1.94%
Benalla (RC)	6014.00	0.27%	92.00	0.02%	1520.00	0.27%	23.25	0.02%
Boroondara (C)	62793.00	2.80%	13237.00	2.21%	24792.00	4.38%	5226.25	3.45%
Brimbank (C)	64850.00	2.89%	13780.00	2.30%	13241.00	2.34%	2813.58	1.86%
Buloke (S)	2698.00	0.12%	-234.00	-0.04%	1012.00	0.18%	-87.77	-0.06%
Campaspe (S)	14815.00	0.66%	1924.00	0.32%	4173.00	0.74%	541.94	0.36%
Cardinia (S)	32658.00	1.46%	18804.00	3.13%	7487.00	1.32%	4310.91	2.85%
Casey (C)	96226.00	4.29%	42242.00	7.04%	18542.00	3.27%	8139.70	5.37%
Central Goldfields (S)	5780.00	0.26%	439.00	0.07%	853.00	0.15%	64.79	0.04%
Colac-Otway (S)	8662.00	0.39%	290.00	0.05%	2267.00	0.40%	75.90	0.05%
Corangamite (S)	6486.00	0.29%	37.00	0.01%	2343.00	0.41%	13.37	0.01%
Darebin (C)	58412.00	2.61%	13907.00	2.32%	11743.00	2.07%	2795.83	1.85%
East Gippsland (S)	19147.00	0.85%	3670.00	0.61%	4285.00	0.76%	821.33	0.54%
Frankston (C)	52699.00	2.35%	8434.00	1.41%	9792.00	1.73%	1567.12	1.03%
Gannawarra (S)	4509.00	0.20%	-181.00	-0.03%	1367.00	0.24%	-54.87	-0.04%
Glen Eira (C)	54732.00	2.44%	10518.00	1.75%	15253.00	2.69%	2931.21	1.94%
Glenelg (S)	8250.00	0.37%	336.00	0.06%	1909.00	0.34%	77.75	0.05%
Golden Plains (S)	7557.00	0.34%	1889.00	0.31%	1718.00	0.30%	429.44	0.28%
Greater Bendigo (C)	43971.00	1.96%	10835.00	1.81%	7723.00	1.36%	1903.04	1.26%
Greater Dandenong (C)	51167.00	2.28%	12062.00	2.01%	13367.00	2.36%	3151.11	2.08%
Greater Geelong (C)	91808.00	4.09%	21347.00	3.56%	16625.00	2.93%	3865.61	2.55%
Greater Shepparton (C)	24406.00	1.09%	4172.00	0.70%	6348.00	1.12%	1085.14	0.72%
Hepburn (S)	6638.00	0.30%	877.00	0.15%	1429.00	0.25%	188.80	0.12%
Hindmarsh (S)	2452.00	0.11%	-250.00	-0.04%	762.00	0.13%	-77.69	-0.05%
Hobsons Bay (C)	34199.00	1.53%	7743.00	1.29%	6811.00	1.20%	1542.08	1.02%
Horsham (RC)	8079.00	0.36%	1050.00	0.18%	2140.00	0.38%	278.13	0.18%
Hume (C)	63208.00	2.82%	24820.00	4.14%	14360.00	2.53%	5638.77	3.72%
Indigo (S)	6265.00	0.28%	624.00	0.10%	1743.00	0.31%	173.60	0.11%
Kingston (C)	58767.00	2.62%	11889.00	1.98%	15970.00	2.82%	3230.85	2.13%
Knox (C)	55441.00	2.47%	11589.00	1.93%	12980.00	2.29%	2713.25	1.79%
Latrobe (C)	30282.00	1.35%	3253.00	0.54%	4213.00	0.74%	452.58	0.30%
Loddon (S)	3321.00	0.15%	-2.00	0.00%	1041.00	0.18%	-0.63	0.00%
Macedon Ranges (S)	16766.00	0.75%	4429.00	0.74%	4601.00	0.81%	1215.43	0.80%
Manningham (C)	41546.00	1.85%	8463.00	1.41%	13029.00	2.30%	2654.03	1.75%
Mansfield (S)	3538.00	0.16%	324.00	0.05%	1156.00	0.20%	105.86	0.07%
Maribyrnong (C)	32737.00	1.46%	14447.00	2.41%	6569.00	1.16%	2898.93	1.91%
Maroondah (C)	41360.00	1.84%	9215.00	1.54%	8984.00	1.59%	2001.63	1.32%
Melbourne (C)	65792.00	2.93%	36287.00	6.05%	37026.00	6.54%	20421.37	13.48%
Melton (S)	43980.00	1.96%	31227.00	5.21%	7024.00	1.24%	4987.23	3.29%
Mildura (RC)	21654.00	0.97%	3208.00	0.53%	5206.00	0.92%	771.26	0.51%
Mitchell (S)	14862.00	0.66%	8603.00	1.43%	2883.00	0.51%	1668.85	1.10%
Moira (S)	11736.00	0.52%	2048.00	0.34%	3099.00	0.55%	540.79	0.36%
Monash (C)	64914.00	2.89%	11527.00	1.92%	19509.00	3.44%	3464.28	2.29%
Moonee Valley (C)	46012.00	2.05%	9533.00	1.59%	10617.00	1.87%	2199.68	1.45%
Moorabool (S)	11848.00	0.53%	4641.00	0.77%	2653.00	0.47%	1039.21	0.69%
Moreland (C)	64683.00	2.88%	16873.00	2.81%	12292.00	2.17%	3206.45	2.12%
Mornington Peninsula (S)	61106.00	2.73%	11668.00	1.95%	14385.00	2.54%	2746.77	1.81%
Mount Alexander (S)	7939.00	0.35%	1102.00	0.18%	1525.00	0.27%	211.68	0.14%
Moyne (S)	6372.00	0.28%	892.00	0.15%	2264.00	0.40%	316.93	0.21%
Murrindindi (S)	5753.00	0.26%	986.00	0.16%	1701.00	0.30%	291.53	0.19%
Nillumbik (S)	20436.00	0.91%	3901.00	0.65%	6351.00	1.12%	1212.33	0.80%
Northern Grampians (S)	5105.00	0.23%	17.00	0.00%	1198.00	0.21%	3.99	0.00%
Port Phillip (C)	50603.00	2.26%	14382.00	2.40%	19700.00	3.48%	5598.98	3.70%
Pyrenees (S)	2942.00	0.13%	455.00	0.08%	788.00	0.14%	121.87	0.08%
Queenscliffe (B)	1298.00	0.06%	172.00	0.03%	339.00	0.06%	44.92	0.03%
South Gippsland (S)	11719.00	0.52%	1235.00	0.21%	3648.00	0.64%	384.44	0.25%
Southern Grampians (S)	6670.00	0.30%	155.00	0.03%	2020.00	0.36%	46.94	0.03%
Stonnington (C)	47416.00	2.11%	12023.00	2.00%	17305.00	3.05%	4387.93	2.90%
Strathbogie (S)	4532.00	0.20%	343.00	0.06%	1363.00	0.24%	103.16	0.07%
Surf Coast (S)	10879.00	0.49%	3445.00	0.57%	3235.00	0.57%	1024.41	0.68%
Swan Hill (RC)	8231.00	0.37%	493.00	0.08%	2495.00	0.44%	149.44	0.10%
Towong (S)	2508.00	0.11%	43.00	0.01%	911.00	0.16%	15.62	0.01%
Unincorporated Vic	744.00	0.03%	-396.00	-0.07%	142.00	0.03%	-75.58	-0.05%
Wangaratta (RC)	11666.00	0.52%	558.00	0.09%	3054.00	0.54%	146.08	0.10%
Warrnambool (C)	13549.00	0.60%	2285.00	0.38%	2770.00	0.49%	467.15	0.31%
Wellington (S)	17341.00	0.77%	1638.00	0.27%	4025.00	0.71%	380.19	0.25%
West Wimmera (S)	1655.00	0.07%	-136.00	-0.02%	791.00	0.14%	-65.00	-0.04%
Whitehorse (C)	60429.00	2.69%	11433.00	1.91%	15328.00	2.71%	2900.02	1.91%
Whittlesea (C)	66530.00	2.97%	29734.00	4.96%	12624.00	2.23%	5642.00	3.73%
Wodonga (RC)	15132.00	0.67%	4581.00	0.76%	2797.00	0.49%	846.75	0.56%
Wyndham (C)	70302.00	3.14%	37585.00	6.27%	13142.00	2.32%	7026.00	4.64%
Yarra (C)	39868.00	1.78%	12033.00	2.01%	14318.00	2.53%	4321.47	2.85%
Yarra Ranges (S)	54100.00	2.41%	10317.00	1.72%	13049.00	2.30%	2488.48	1.64%
Yarriambiack (S)	2869.00	0.13%	-82.00	-0.01%	1011.00	0.18%	-28.90	-0.02%
	2242284.00	100%	599849.00	100%	566518.00	100%	151439.05	100%

LGA	Median Weekly Household Income ($)	Prop_HH_Income	Wind Resource (High)	Prop_High_Wind_Resource	Solar Resource (High)	Prop_High_Solar_Resource	Total Installed Solar Capacity	Prop_SolarCap
Alpine (S)	1002.00	0.98%		0.00%		0.00%	6,049	0.46%
Ararat (RC)	991.00	0.97%	High	10.00%		0.00%	3,513	0.27%
Ballarat (C)	1160.00	1.13%		0.00%		0.00%	25,267	1.92%
Banyule (C)	1655.00	1.61%		0.00%		0.00%	26,564	2.02%
Bass Coast (S)	922.00	0.90%		0.00%		0.00%	16,500	1.26%
Baw Baw (S)	1196.00	1.16%		0.00%		0.00%	26,916	2.05%
Bayside (C)	2145.00	2.09%		0.00%		0.00%	15,409	1.17%
Benalla (RC)	946.00	0.92%		0.00%		0.00%	7,785	0.59%
Boroondara (C)	2083.00	2.03%		0.00%		0.00%	20,029	1.53%
Brimbank (C)	1263.00	1.23%		0.00%		0.00%	59,565	4.54%
Buloke (S)	839.00	0.82%		0.00%	High	8.33%	4,322	0.33%
Campaspe (S)	1081.00	1.05%		0.00%	High	8.33%	20,692	1.58%
Cardinia (S)	1497.00	1.46%		0.00%		0.00%	29,529	2.25%
Casey (C)	1554.00	1.51%		0.00%		0.00%	73,531	5.60%
Central Goldfields (S)	775.00	0.75%	High	10.00%		0.00%	6,727	0.51%
Colac-Otway (S)	1057.00	1.03%	High	10.00%		0.00%	6,706	0.51%
Corangamite (S)	1043.00	1.02%	High	10.00%		0.00%	6,520	0.50%
Darebin (C)	1423.00	1.39%		0.00%		0.00%	23,083	1.76%
East Gippsland (S)	935.00	0.91%	High	10.00%		0.00%	22,237	1.69%
Frankston (C)	1331.00	1.30%		0.00%		0.00%	24,646	1.88%
Gannawarra (S)	908.00	0.88%		0.00%	High	8.33%	7,486	0.57%
Glen Eira (C)	1741.00	1.70%		0.00%		0.00%	15,079	1.15%
Glenelg (S)	1043.00	1.02%	High	10.00%		0.00%	4,666	0.36%
Golden Plains (S)	1448.00	1.41%		0.00%		0.00%	10,115	0.77%
Greater Bendigo (C)	1184.00	1.15%		0.00%		0.00%	23,612	1.80%
Greater Dandenong (C)	1168.00	1.14%		0.00%		0.00%	25,601	1.95%
Greater Geelong (C)	1244.00	1.21%		0.00%		0.00%	59,030	4.50%
Greater Shepparton (C)	1163.00	1.13%		0.00%		0.00%	25,422	1.94%
Hepburn (S)	996.00	0.97%		0.00%		0.00%	5,133	0.39%
Hindmarsh (S)	907.00	0.88%		0.00%	High	8.33%	3,199	0.24%
Hobsons Bay (C)	1567.00	1.53%		0.00%		0.00%	14,563	1.11%
Horsham (RC)	1110.00	1.08%		0.00%	High	8.33%	8,161	0.62%
Hume (C)	1379.00	1.34%		0.00%		0.00%	48,660	3.71%
Indigo (S)	1265.00	1.23%		0.00%		0.00%	10,942	0.83%
Kingston (C)	1537.00	1.50%		0.00%		0.00%	25,486	1.94%
Knox (C)	1561.00	1.52%		0.00%		0.00%	35,492	2.70%
Latrobe (C)	1078.00	1.05%		0.00%		0.00%	9,403	0.72%
Loddon (S)	826.00	0.80%		0.00%	High	8.33%	17,072	1.30%
Macedon Ranges (S)	1638.00	1.60%		0.00%		0.00%	17,302	1.32%
Manningham (C)	1642.00	1.60%		0.00%		0.00%	15,402	1.17%
Mansfield (S)	1062.00	1.03%		0.00%		0.00%	3,694	0.28%
Maribyrnong (C)	1551.00	1.51%		0.00%		0.00%	5,732	0.44%
Maroondah (C)	1544.00	1.50%		0.00%		0.00%	22,282	1.70%
Melbourne (C)	1354.00	1.32%		0.00%		0.00%	8,374	0.64%
Melton (S)	1542.00	1.50%		0.00%		0.00%	35,024	2.67%
Mildura (RC)	1064.00	1.04%		0.00%	High	8.33%	21,519	1.64%
Mitchell (S)	1391.00	1.35%		0.00%		0.00%	9,038	0.69%
Moira (S)	1014.00	0.99%		0.00%		0.00%	20,590	1.57%
Monash (C)	1512.00	1.47%		0.00%		0.00%	24,499	1.87%
Moonee Valley (C)	1635.00	1.59%		0.00%		0.00%	14,225	1.08%
Moorabool (S)	1391.00	1.35%		0.00%		0.00%	9,989	0.76%
Moreland (C)	1503.00	1.46%		0.00%		0.00%	11,275	0.86%
Mornington Peninsula (S)	1276.00	1.24%		0.00%		0.00%	41,872	3.19%
Mount Alexander (S)	1002.00	0.98%		0.00%		0.00%	13,178	1.00%
Moyne (S)	1225.00	1.19%		0.00%		0.00%	12,287	0.94%
Murrindindi (S)	1071.00	1.04%		0.00%		0.00%	9,278	0.71%
Nillumbik (S)	2098.00	2.04%		0.00%		0.00%	18,732	1.43%
Northern Grampians (S)	931.00	0.91%		0.00%	High	8.33%	3,583	0.27%
Port Phillip (C)	1842.00	1.79%		0.00%		0.00%	4,256	0.32%
Pyrenees (S)	876.00	0.85%	High	10.00%	High	8.33%	1,980	0.15%
Queenscliffe (B)	1173.00	1.14%		0.00%		0.00%	-	0.00%
South Gippsland (S)	1039.00	1.01%	High	10.00%		0.00%	12,378	0.94%
Southern Grampians (S)	1043.00	1.02%		0.00%		0.00%	3,670	0.28%
Stonnington (C)	1944.00	1.89%		0.00%		0.00%	3,500	0.27%
Strathbogie (S)	962.00	0.94%		0.00%		0.00%	5,537	0.42%
Surf Coast (S)	1571.00	1.53%		0.00%		0.00%	11,654	0.89%
Swan Hill (RC)	1094.00	1.07%		0.00%	High	8.33%	10,842	0.83%
Towong (S)	1043.00	1.02%		0.00%		0.00%	2,518	0.19%
Unincorporated Vic	1087.00	1.06%		0.00%		0.00%	292	0.02%
Wangaratta (RC)	1085.00	1.06%		0.00%		0.00%	13,378	1.02%
Warrnambool (C)	1182.00	1.15%	High	10.00%		0.00%	-	0.00%
Wellington (S)	1101.00	1.07%	High	10.00%		0.00%	24,798	1.89%
West Wimmera (S)	987.00	0.96%		0.00%	High	8.33%	893	0.07%
Whitehorse (C)	1507.00	1.47%		0.00%		0.00%	13,945	1.06%
Whittlesea (C)	1444.00	1.41%		0.00%		0.00%	29,217	2.23%
Wodonga (RC)	1273.00	1.24%		0.00%		0.00%	10,176	0.78%
Wyndham (C)	1620.00	1.58%		0.00%		0.00%	27,470	2.09%
Yarra (C)	1958.00	1.91%		0.00%		0.00%	5,900	0.45%
Yarra Ranges (S)	1501.00	1.46%		0.00%		0.00%	34,559	2.63%
Yarriambiack (S)	885.00	0.86%		0.00%	High	8.33%	3,153	0.24%
	102686.00	100%			0.00		1,312,708	100%

Appendix B: Mapping LGAs to Terminal Stations serving the Businesses

The following is an extract from the underlying model. It shows how each LGA is mapped to each terminal station.

	RCTS_22kV	RCTS_66kV	WETS_66kV	KGTS_22kV	KGTS_66kV	HOTS_66kV	BETS_22kV	BETS_66kV	SHTS_GNTS	HYTS_TGTS_APD	BATS_ELTS	MLTS_GTS_PTH	ATS_West	ATS_BLTS	BLTS_22kV	KTS_East	KTS_West	WMTS_66kV	WMTS_22kV	BTS_22kV	FBTS_66kV	RTS_66kV_Bus1and4	RTS_66kV_Bus2and3	RTS_22kV	SVTS_66kV	TSTS_66kV
ARARAT RURAL CITY COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
BALLARAT CITY COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
BENALLA RURAL CITY COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
BOROONDARA CITY COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	25%	0%	25%	50%
QUEENSCLIFFE BOROUGH COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0	0	0	0
BRIMBANK CITY COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	67%	33%	0%	0%	0%	0%	0%	0%	0%	0%	0%
BULOKE SHIRE COUNCIL	0%	0%	20%	0%	0%	0%	0%	80%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
CAMPASPE SHIRE COUNCIL	0%	0%	0%	0%	15%	0%	0%	0%	85%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
CENTRAL GOLDFIELDS SHIRE COUNCIL	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
COLAC OTWAY SHIRE COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
CORANGAMITE SHIRE COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
DAREBIN CITY COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	75%	0%	25%	0%	0%	0%	0%	0%	0%
GANNAWARRA SHIRE COUNCIL	0%	0%	0%	15%	60%	0%	0%	25%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
GLEN EIRA CITY COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%
GLENELG SHIRE COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
GOLDEN PLAINS SHIRE COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	50%	50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
GREATER BENDIGO CITY COUNCIL	0%	0%	0%	0%	0%	0%	10%	90%	0%	0%	0%	0%	0%	0%	0%	0	0	0%	0%	0%	0%	0%	0%	0%	0%	0%
GREATER GEELONG CITY COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
GREATER SHEPPARTON CITY COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
HEPBURN SHIRE COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
HINDMARSH SHIRE COUNCIL	0%	0%	33%	0%	0%	67%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
HOBSONS BAY CITY COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	25%	55%	20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
HORSHAM RURAL CITY COUNCIL	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
HUME CITY COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
LODDON SHIRE COUNCIL	0%	0%	0%	0%	20%	0%	7%	73%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
MACEDON RANGES SHIRE COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%
MARIBYRNONG CITY COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
MELBOURNE CITY COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	30%	50%	0%	0%	10%	0%	10%	0%	0%
MELTON CITY COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%
MILDURA RURAL CITY COUNCIL	11%	39%	50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
MITCHELL SHIRE COUNCIL	0%	0%	0%	0%	0%	0%	0%	50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
MOIRA SHIRE COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
MOONEE VALLEY CITY COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
MOORABOOL SHIRE COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	80%	0%	0%	20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
MORELAND CITY COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	50%	0%	50%	0%	0%	0%	0%	0%	0%
MOUNT ALEXANDER SHIRE COUNCIL	0%	0%	0%	0%	0%	0%	7%	93%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
MOYNE SHIRE COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
NORTHERN GRAMPIANS SHIRE COUNCIL	0%	0%	0%	0%	0%	75%	0%	25%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
PORT PHILLIP CITY COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	90%	0%	10%	0%	0%	0%
PYRENEES SHIRE COUNCIL	0%	0%	0%	0%	0%	0%	0%	50%	0%	0%	50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
SOUTHERN GRAMPIANS SHIRE COUNCIL	0%	0%	0%	0%	0%	25%	0%	0%	0%	75%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
STONNINGTON CITY COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	40%	40%	20%	0%	0%
STRATHBOGIE SHIRE COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
SURF COAST SHIRE COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
SWAN HILL RURAL CITY COUNCIL	0%	0%	50%	0%	50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
WARRNAMBOOL CITY COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
WELLINGTON SHIRE COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
WEST WIMMERA SHIRE COUNCIL	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
WHITEHORSE CITY COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
WYNDHAM CITY COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
YARRA CITY COUNCIL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	30%	30%	30%	10%	0%	0%
YARRIAMBIACK SHIRE COUNCIL	0%	0%	25%	0%	0%	75%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(blank)	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

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