Distributed generation inquiry

Essential Services Commission

Network benefits report

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Project Manager:	Rohan Zauner
Author:	Rohan Zauner
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Jacobs Australia Pty Limited

Floor 11, 452 Flinders Street
Melbourne VIC 3000
PO Box 312, Flinders Lane
Melbourne VIC 8009 Australia
T +61 3 8668 3000
F +61 3 8668 3001
www.jacobs.com

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Contents

Appendix D. Nomenclature

Executive Summary

Jacobs Group (Australia) Pty Ltd (Jacobs) has been engaged by the Essential Services Commission (ESC) to undertake a technical review of the benefits provided to Victorian electricity networks by distributed generation (DG) in Victoria.

This is to inform the ESC's inquiry into the true value of distributed generation (the Inquiry).

The Inquiry involves two separate but related stages. The first looked at the energy value (and the value of reduced electricity losses) of distributed generation, and the second looks at the network value. In both stages, the ESC is looking at the economic, social and environmental benefits that arise from distributed generation.

This report addresses the second stage – the benefits that are provided by DG to electricity networks (being the electrical transmission and distribution systems). The report focusses on benefits alone, and does not consider potential costs that could be incurred by the networks resulting from higher levels of DG on the grid.

The primary benefit identified is the benefit provided by the capacity of the DG, when it is available at the key times of the year, to defer augmentation of the network and to reduce the customers' exposure to lost load at times when the load might exceed the network's capability if the DG were not present.

Approach

The annual benefit provided by DG was estimated using a counter-factual analysis that considered the network costs in a relevant year if DG were not present, less network costs in that year when DG is present. The costs arise from:

- The costs of augmenting the network to supply the load (annualised cost of network upgrades where these are avoided or deferred by the DG, and
- To the extent the network at some times cannot supply the load (a probabilistic outcome), the cost to customers of this probability of unserved energy. This cost is borne by customers rather than being initially borne by the network owners and is included as this review considers the benefits provided to all entities beyond the DG owner.

The calculation used applies the same process as a distributor would use to evaluate the timing of a network upgrade to justify making an augmentation. The upgrade would, or should, occur at the time when the annual value of customer unserved energy[1] rises to above the annualised cost of the network augmentation.

The assessment considered the additive benefit across all asset classes owned by network operators from distribution feeder to transmission level operation, and was undertaken considering locational factors at each zone substation geographical area, mainly because this is the smallest geographic region for which data is publically available. Sub-transmission and terminal station elements of the network were mapped to the zone substation regions for presentation purposes. Data has been sourced from the distributors' Annual Planning Reports which provide projections for five years ahead. The calculation focuses on the earliest future year of the report (2017) with indicative values also calculated for following years. As new Annual Planning Reports are released, the data for future years would change. Calculated benefits were not provided for the distribution network elements below the zone substation level as no reliable method (with associated data) was found to calculate these.

[1] Also known as reduced customer reliability

Results

Within the Victorian geographical region, 224 zone substation areas were assessed. The results represent the deferral of network augmentation due to distributed generation alleviating network constraints in Victoria and the change in probability of unserved energy benefit. The results consider the value of existing and forecasted distributed generation in 2017 and are summarised by zone substation area and summed over the zone substation, sub-transmission feeder and terminal station asset categories. The results assessed the benefits from three overarching DG types, including solar photovoltaic (PV) technologies, wind technologies and dispatchable generation. In the context of this report “dispatchable” generation means all generation types that are able to dispatch when required to minimise network costs (i.e. is optimised to the network’s needs).

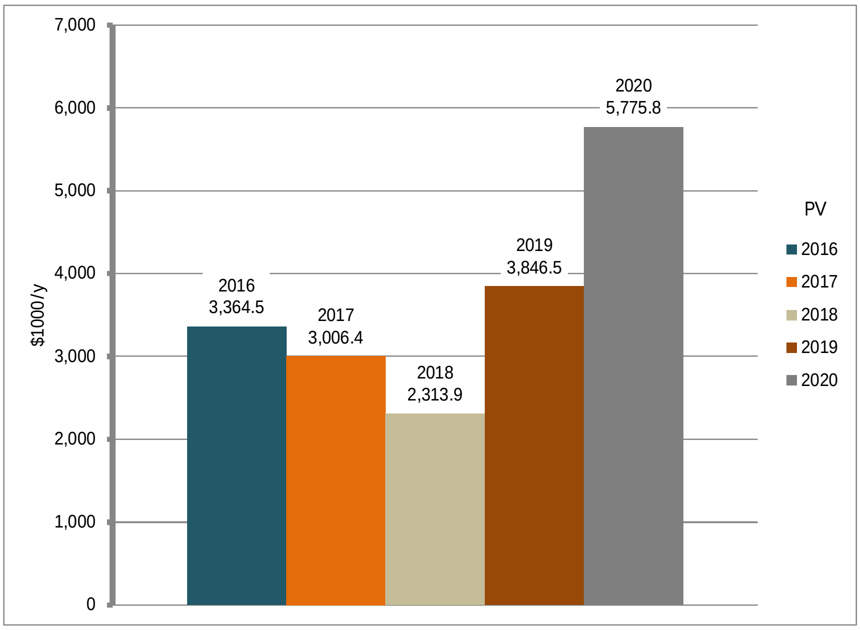
In making the calculations, the benefits of generator types (PV versus dispatchable) are calculated separately. These are not generally additive as in some cases they will be providing the same benefit and in some cases the combination will provide an enhanced benefit. The combination of benefit may be higher or lower than the sum of benefits depending on the circumstances at the relevant point in the network and is discussed in Section 3.6.

Solar PV systems

The estimated quantity of PV DG in the Victorian network in 2017 is 1,088 MW (nameplate rating). In 2017, six zone substation areas showed benefit of more than $10/kW of installed capacity (ranging to around $35/kW of installed capacity), while 106 zone substation areas indicated a benefit below $10/kW and 112 areas show zero benefit. Where zero benefits were evident, these occurred because there was sufficient network capacity such that even with a transformer failure, or without a subtransmission feeder operating, there was no unserved energy risk and hence no need to augment. Some locations were assigned zero benefit where insufficient data existed to undertake a calculation. PV was able to defer network investment in all levels of the network albeit generally at different locations and in different years.

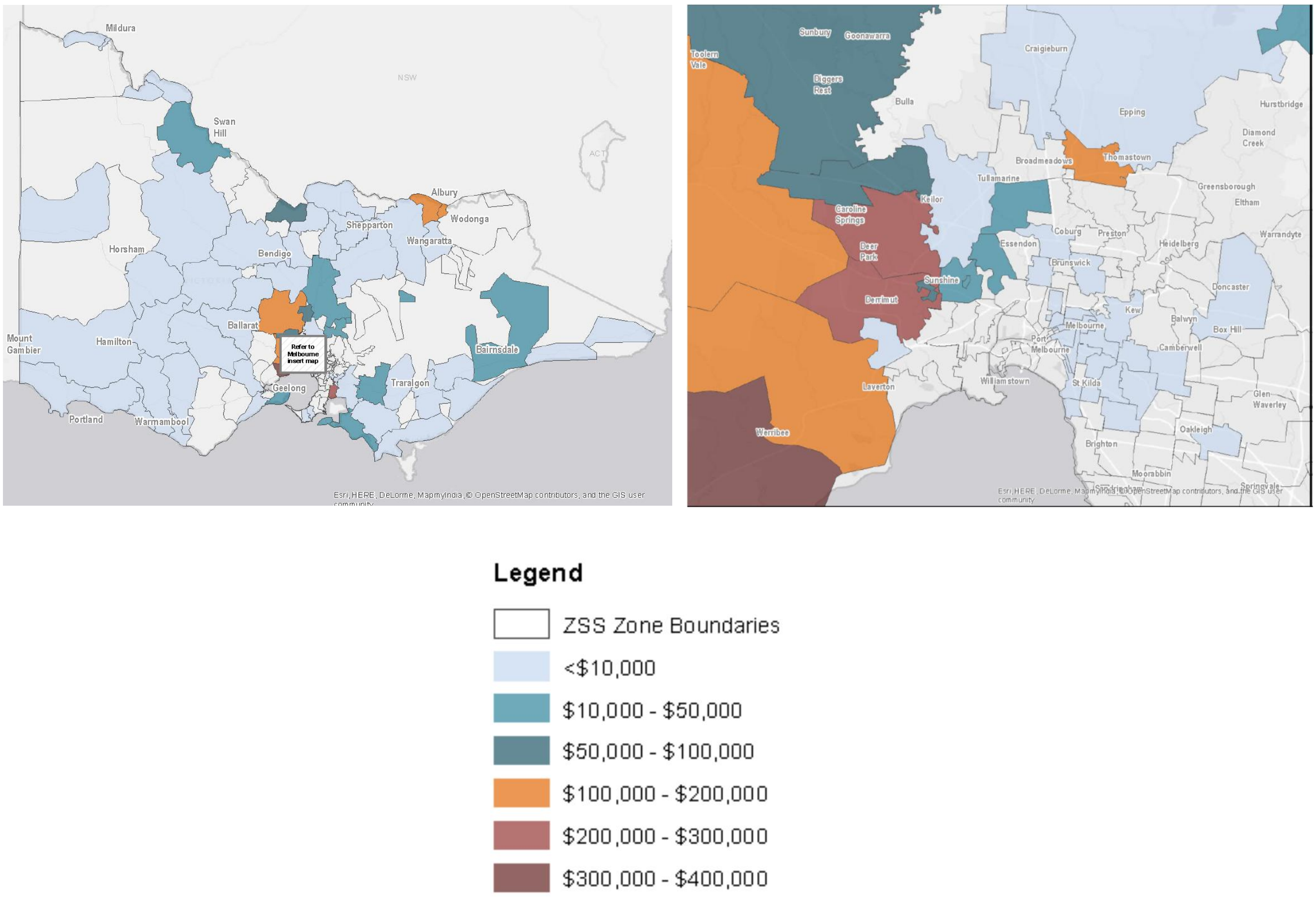
It was evident that values can vary significantly from year-to-year. Locations can have increasing benefits with time or the benefits can drop-off – typically after an augmentation is undertaken which would be required with or without the DG. The total calculated benefit of existing and forecast PV in Victoria in 2017 was $3.01 million in 2017 rising to $5.78 million in 2020. See Figure 1.

Figure 1 Calculated benefits of existing (and forecast) PV in Victoria



Maps showing the locational variations in benefits for existing PV in greater Victoria and the Melbourne metropolitan area are shown in Figure 2.

Figure 2 Existing PV benefit in 2017, $/year



Potential maximum benefit of Dispatchable DG

Dispatchable distributed generation (in this report) is distinguished from PV in being able to generate when called for at any time of day in a manner that best supports the network, whether the sun is shining (or wind blowing) or not.

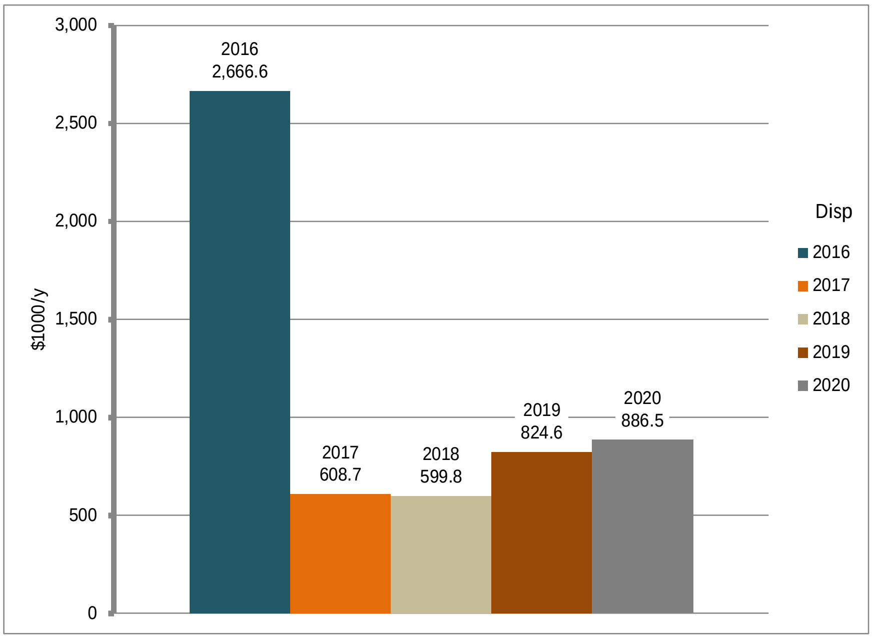
The estimated level of dispatchable DG generation in Victoria in 2017 is 124 MW. There are no estimates of the change in quantity of dispatchable DG over the analysis period other than as already included within the DNSP load forecasts (but these are not separately identifiable). In addition to generation technologies, Jacobs have modelled (in other work for AEMO[2]) 19 MW of batteries (integrated with PV) in Victoria in 2017.

The generation levels of existing dispatchable DG cannot be reliably estimated at any time of day as the decision as to when the generator operates is generally made by the owner and operator of the generator and operation is not necessarily directed to providing network benefits. The calculated benefits for dispatchable DG are the maximum benefits that would arise if the operation was directed to maximising value to the network as opposed to being configured to provide some alternative benefit (such as lowest electricity cost to the consumer).

[2] Jacobs report: “Projections of uptake of small scale systems" June 2016 for AEMO (NEFR2016)

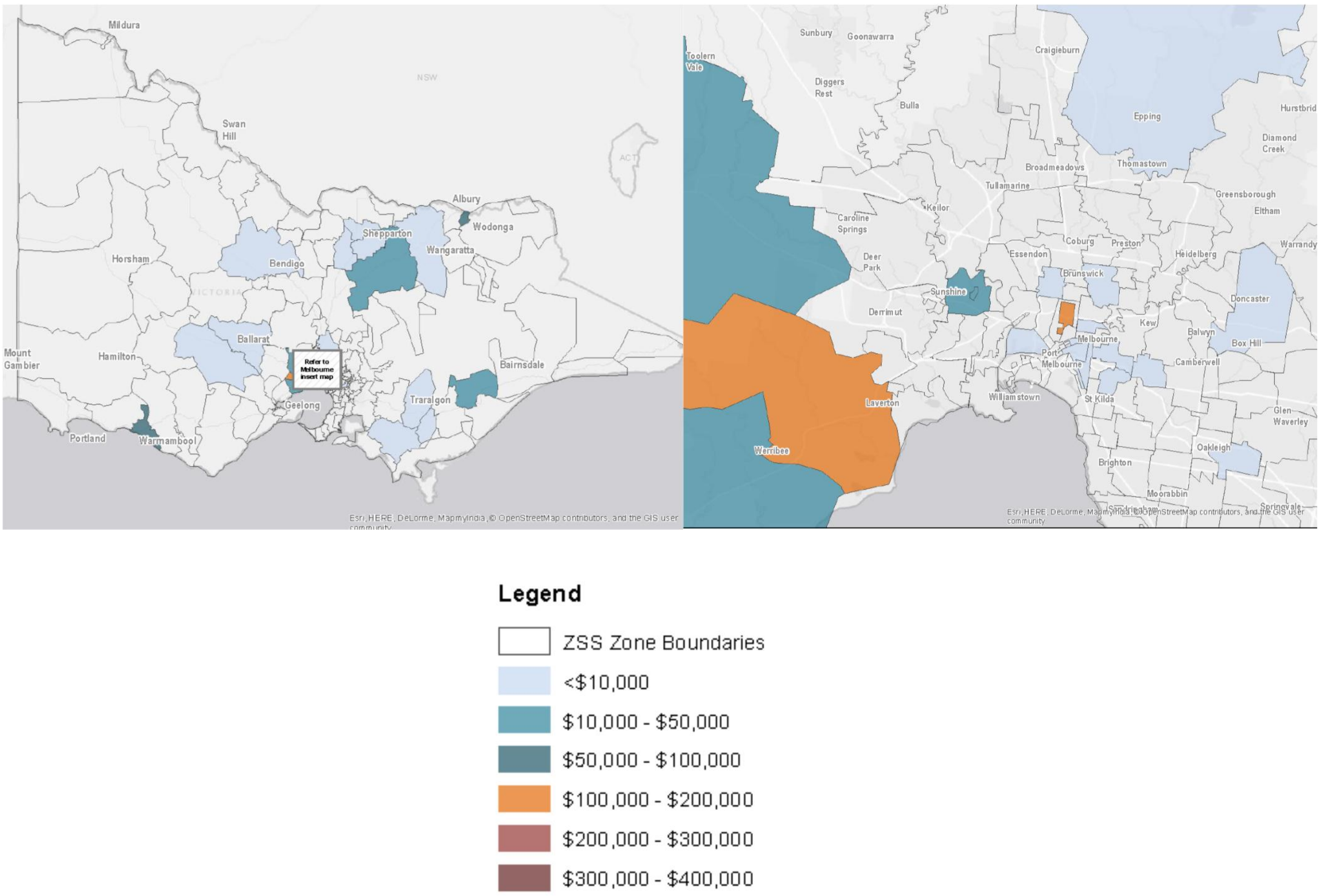
Potential benefits above $10/kW are present for 25 zone substation areas (ranging to around $57/kW), compared with 66 areas with benefits of less than $10/kW and 133 areas with zero calculated benefit. In areas where benefits exceed $10/kW, 94% comes from avoided terminal station capital spending and value of customer reliability changes, and 6% comes from avoided zone substation capital expenditure and value of customer reliability changes. As with PV, there is variation in benefit over the period 2016-2020, ranging to nearly three times the 2017 benefit in 2017 in certain locations in Western Victoria. Calculated total potential benefits over the Victorian system in 2017 are $609,000 and grow to $887,000 in 2020 as shown in Figure 3.

Figure 3 Calculated benefits of existing dispatchable DG in Victoria



Maps showing the locational variations in benefits for existing dispatchable DG in greater Victoria and the Melbourne metropolitan area are shown in Figure 4.   Additional maps are provided in Appendix B.

Figure 4 Existing dispatchable generation benefit in 2017, $/year



When comparing the solar values to the dispatchable values, the solar PV values are generally lower on a "per kW" basis. This is because the solar PV systems are only able to generate when the sun is shining and hence do not deliver the same benefit relative to their capacity during later afternoon peak periods when limited insolation levels apply. PV provides an overall larger benefit (in dollars per year) because of the significantly greater quantity of PV relative to other forms of DG.

Wind systems

Only Ballarat North and South ZSSs have a material amount of small wind capacity (4.1 and 6.15 MW respectively). Three other ZSSs have immaterial quantities of small wind (< 0.2 MW each). No separate benefit value has been presented except Jacobs has analysed a case with all DG present (PV, dispatchable and wind) to estimate an overall value.

Benefit of distributed generation

Jacobs has assessed that in 2017, DG has provided an overall benefit of $3.8 million/year in 2017. For comparison, the quantity of augmentation capital expenditure undertaken by the Victorian distributors is of the order of $100 to $200 million/year. For the dispatchable component of DG this assumes the DG is configured to provide the optimum network benefit as opposed to be optimised for some other purpose. Considering that dispatchable generation will not always be configured this way under present arrangements, this represents potential benefit.

The benefit of DG to networks is primarily contained in the capacity of the DG (rather than in the exported electricity amount) that is available at the time of maximum network demand, which is late afternoon for most locations in the network.

Important note about your report

This report has been developed as a technical document for the Essential Services Commission (ESC) to demonstrate the network value of distributed generation. This review is undertaken on behalf of the Essential Services Commission in accordance with the scope of services set out in the contract between Jacobs and ESC.

In preparing this report, Jacobs has relied upon, and presumed accurate, information (or confirmation of the absence thereof) provided by ESC and from other sources. Except as otherwise stated in the report, Jacobs has not attempted to verify the accuracy or completeness of any such information. If the information is subsequently determined to be false, inaccurate or incomplete then it is possible that our observations and conclusions as expressed in this report may change.

This report should be read in full and no excerpts are to be taken as representative of the findings. No responsibility is accepted by Jacobs for use of any part of this report in any other context.

The passage of time, manifestation of latent conditions or impacts of future events may require further examination of the project and subsequent data analysis, and re-evaluation of the data, findings, observations and conclusions expressed in this report. Jacobs has prepared this report in accordance with the usual care and thoroughness of the consulting profession, for the sole purpose described above and by reference to applicable standards, guidelines, procedures and practices at the date of issue of this report. For the reasons outlined above, however, no other warranty or guarantee, whether expressed or implied, is made as to the data, observations and findings expressed in this report, to the extent permitted by law.

This report has been prepared on behalf of, and for the exclusive use of ESC, and is subject to, and issued in accordance with, the provisions of the contract between Jacobs and ESC. Jacobs accepts no liability or responsibility whatsoever for, or in respect of, any use of, or reliance upon, this report by any third party

1. Introduction

1.1 General

Jacobs Group (Australia) Pty Ltd (Jacobs) has been engaged by the Essential Services Commission (ESC) to undertake a technical review of the benefits provided to Victorian electricity networks by distributed generation (DG) in Victoria.

In September 2015, ESC received a terms of reference under section 41 of the Essential Services Commission Act 2001, to carry out an inquiry into the true value of distributed generation (the Inquiry).

The Inquiry involves two separate but related stages. The first looked at the energy value (and the value of reduced electricity losses) of distributed generation, and the second looks at the network value. In both stages, ESC are looking at the economic, social and environmental benefits that arise from distributed generation.

Further details and documents related to the Inquiry are located at: http://www.esc.vic.gov.au/project/energy/22790-inquiry-into-the-true-value-of-distributed-generation-to-victorian-customers/

This report addresses the second stage – the benefits that are provided by DG to electricity networks (being the electrical transmission and distribution systems). The report focusses on benefits alone, and does not consider potential costs that could be incurred by the networks resulting from higher levels of DG on the grid.

The aim of the report is to inform the ESC's deliberations in answering the question "is distributed generation currently providing network value in Victoria?" and, if there is network value, to quantify it. The report is to provide quantified inputs to ESC"s findings on the value that distributed generation does provide. To provide results that might be relevant in the different situations that ESC may need in its later evaluations, the benefits have been calculated and presented on several bases:

- The primary calculation of benefits is to establish for each year of a five year timeframe (2016 to 2020, for which data is available), the economic benefit that is attributable to the presence of DG in the network in that year by calculating the difference in economic costs "with" the DG versus the costs if the DG were not present (ie the "without" case)
- The primary calculations include the benefits provided by the existing DG quantity and also the benefits provided by an incremental unit of DG capacity
- Secondary calculations, or a review of other potential benefits, were also evaluated. A review was undertaken for a range of potential network benefits such as additional network support, voltage regulation and additional congestion benefit. An avoided TUOS charges calculation (similar to that which would apply to larger embedded generators under the NER) was also undertaken for comparison purposes with the transmission benefits calculated and accounted for in the primary calculation.

The analysis underlying the report results is based on an approach designed to give a robust estimate of the benefit of distributed generation with respect to networks. Jacobs has delivered an empirical, data-driven and transparent method that identifies benefits and values that DG may provide to the network.

This document describes the method used to undertake the analysis, provides a summary of the results, and incorporates observations and conclusions based on the results provided.

For the purpose of summarising results this report focuses on 2017. All values presented are in real 2016 Australian dollars, excluding GST, unless noted otherwise.

1.2 Definition of distributed generation

1.2.1 General

ESC has defined distributed generation (DG) for the purposes of this report as:

- Generation up to 5MW
- Normally installed at a customer's site and provides some or all of its electrical output to the host.
- Generation from any source or fuel type
- Battery storage is included when considering possible network benefits and value

Jacobs considered a wide range of DG technologies, including:

- Solar photovoltaic (Solar PV)
- Wind
- Small Hydro
- Cogeneration and tri-generation
- Reciprocating engines (diesel and biodiesel)
- Fuel cells
- Standalone storage
- Storage with small scale generation
- In-plant steam turbines
- Biomass
- Landfill gas and sewage gas
- Small waste to energy projects

This list represents examples of technologies that exist or are potentially relevant in a short-medium timeframe in the future. Technologies that emerge in the long term would be accommodated in a future review although the principles and framework used in this review would still be expected to be applicable in the future.

Consideration of the technologies applicable is primarily to establish the differences in characteristics of the technologies that might produce different benefits. Characteristics which could be considered (depending on the benefit type) include location, size, time dependence of output, controllability, predictability, firmness, metering of gross output or exported output, and current or future smart technologies.

These technologies were classified into the following categories in this report:

- Solar photovoltaic (Solar PV)
- Wind
- Dispatchable forms of generation (Other)

Because it is not known exactly when the dispatchable forms of generation do run, the assumption is made that they would run at the times that there was network benefit in running. This means that the benefits stated for existing dispatchable DG in this report are more properly "potential benefits" rather than benefits that have necessarily been realised in deferred network augmentations or the like.

Given that there are presently few price-signals provided to generators to operate to maximise the network benefit, dispatchable DG would be expected to be operated to maximise the owner's private benefit, which would be substantially based on the facilitiy's own electrical load profile and the energy and network tariff settings specific to their facility.

1.2.2 Network vs proponent-led DG projects

The method for calculating benefits does not need to distinguish between proponent and network led projects as the benefit provided is the same. The difference between proponent and network led projects is that network led projects may be compensated by the network service provider for some of those benefits via a network service agreement. The allocation of the benefits may thus be different. There are presently no DG projects of the size relevant to this report receiving network support payments in Victoria and hence the distinction between proponent led and network led DG is not important in this report.

It is noted that the DNSPs sometimes use portable generators on a short term basis to cover network issues (eg during construction or maintenance) and have some demand management agreements.

1.2.3 Past vs future installations

For the purpose of calculating network benefit, there is no difference between benefits from pre-existing and new installations except that the DG must be extant at the time the benefit is calculated for a benefit to arise. However, there is a requirement by the Inquiry in forming its views on benefit allocation and possible policy amendments, for information for both types of installations to be presented, and so an allocation of benefit to past installations that are presently providing benefit and future installations has been provided. This has enabled calculation of value from pre-existing and incremental new installations (over and above the new installations already allowed for in the DNSPs' forecasts) in the Inquiry's later tasks.

1.3 Amount of DG in Victoria

Using data provided by the distributors and including only DG < 5MW size, the indicative quantity of DG in Victoria, by type, is shown in Table 1.

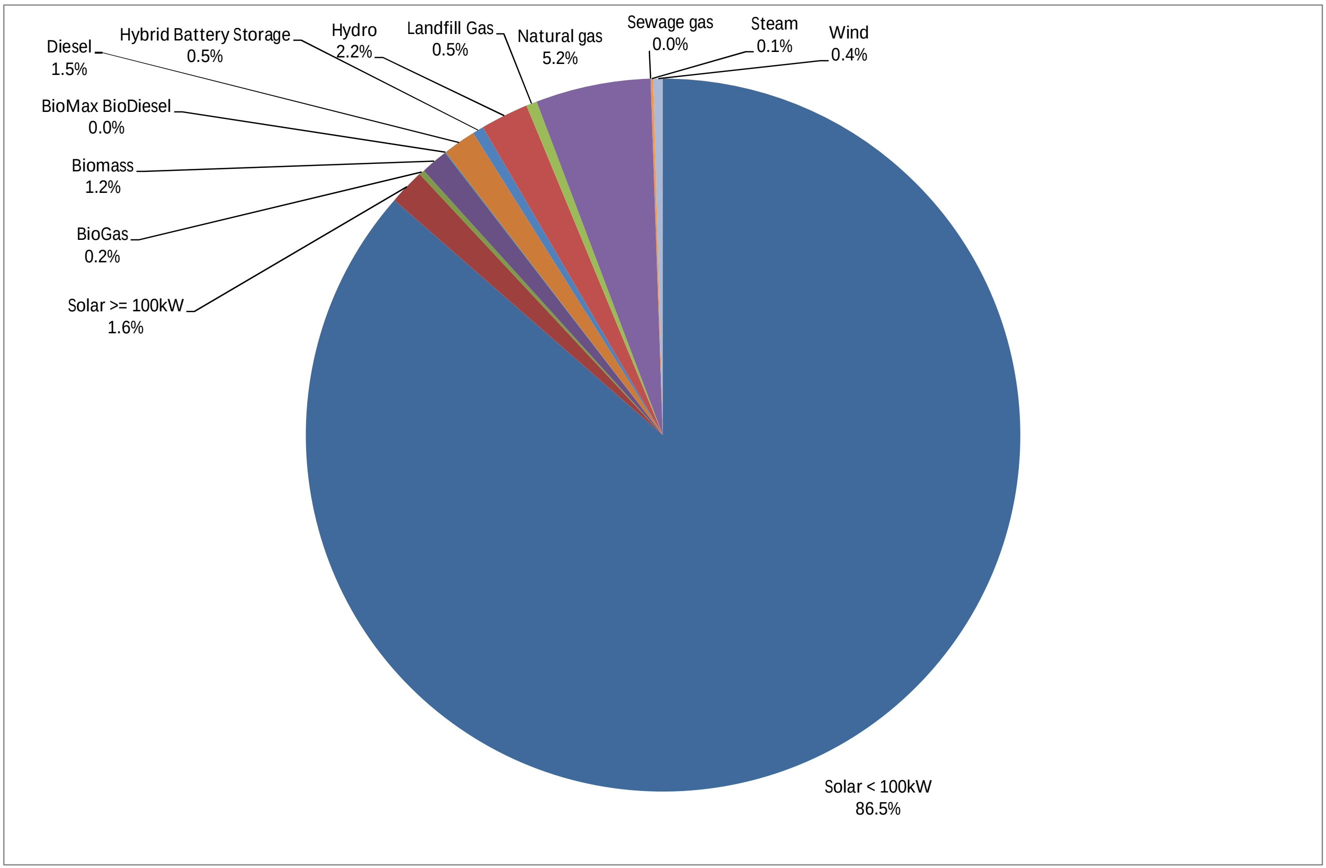
Table 1 DG capacity in Victoria, 2016[3]

DG type	MW
Solar < 100kW	841.8
Solar >= 100kW	15.7
BioGas	2.3
Biomass	12.0
BioMax BioDiesel	0.5
Diesel	14.4
Hybrid Battery Storage	5.0
Hydro	21.1
Landfill Gas	4.9
Natural gas	50.6
Sewage gas	0.0
Steam	1.0
Wind	4.4
Total	**973.7**

[3] Data is not necessarily concurrent as provided by the five distributors and hence this quantity should be considered indicative only for first-half 2016. Data has been provided by the DNSPs

As shown in Figure 5, solar comprises approximately 88% of the DG in Victoria. There is only a small amount of wind generation in the size range below 5 MW, mostly near Ballarat. The balance of DG in Victoria falls into technology categories that are, or could be, dispatchable generation.

Figure 5 DG capacity types in Victoria, 2016



1.4 Benefits

Where Jacobs evaluated that a potential form of benefit could not be quantified robustly they are excluded. Alternative approaches were explored to determine whether material benefit is likely to exist from the excluded form.

Benefits identified are those that produce external benefits (i.e. to other parties rather than to the distributed generation owner). Internal benefits do not need to be identified as they are already allocated to the producer of the benefit. External network derived benefits that accrue collectively to network owners and to other customers due to the DG's presence in the network are included in the analysis.

Connection issues and benefits of DG, and costs that might be imposed by DG are excluded from the analysis under the Inquiry's terms of reference.

2. Method used to determine network benefits

2.1 Introduction

The ways in which DG might provide benefits to the network are considered in Section 2.2. The predominant means by which DG provides a benefit to networks is in reducing augmentation capital costs, and in the related effect of changing the exposure of customers to lost load due to insufficient network capacity.

The scale of augmentation capex that is expended in Victoria's network is discussed in Section 2.3.

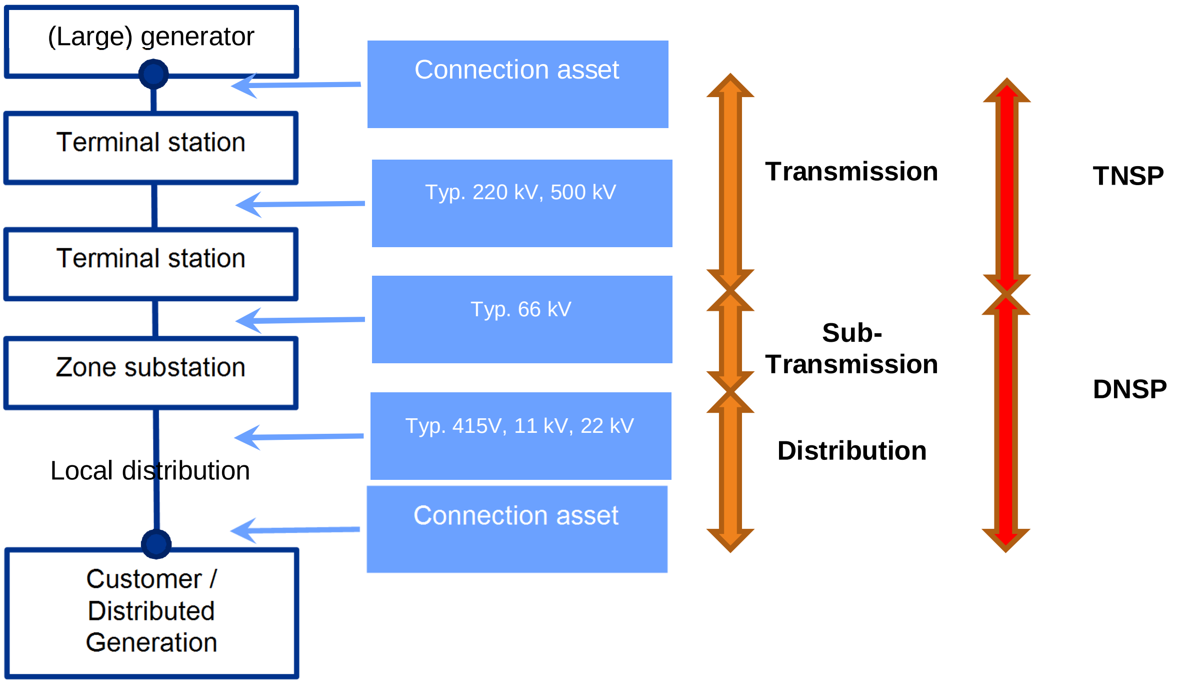
The method developed to estimate the benefits provided by the DG is given in Section 2.4.

The method requires various parameters and assumptions to be applied. These are discussed in Section 2.5.

2.2 Benefits

Electricity networks are made up of separate areas each of which has different parameters and issues. These are illustrated in Figure 6. The transmission system operates at voltages of 220 kV and above, and includes links to terminal stations (which step down voltage levels). The sub-transmission system operates at voltages of (typically) 66 kV and link zone substations to terminal stations. Any asset connected downstream of the zone substation (other than customer owned distributed generation) is considered to be a distribution asset, and lines are typically rated at 22 kV, 11 kV and 415 volts.

Figure 6 Areas of a network



Potential areas where benefits might be found have been identified from ESC's prior knowledge, stakeholders' responses to the ESC's discussion paper, a literature search and from Jacob's knowledge. These potential benefit areas have been screened to establish those that are likely to produce external benefits that are material and measurable.

Table 2 provides an overview of the benefits considered for this study. Benefits that do not benefit the network directly are excluded from the table, as are benefits which have been considered in Phase 1 of the Inquiry (the market benefits review) or would be categorised as social or environmental (which are not in Jacobs' scope).

Table 2 Network benefits of distributed generation

Benefit	Description	Treatment in this study
Network capacity benefits		
Deferral of augmentation capital expenditure (Deferred augex)	Distribution below zone substation level	Some benefit is likely to exist but no method (with associated data) was found that could reliably estimate the benefit. Refer to Section 3.5.
	Zone substation	Calculated. Refer to Section 2.4.2
	Sub-transmission	Calculated. Refer to Section 2.4.4
	Transmission	Calculated at terminal station transformer level. Refer to Section 2.4.3
Avoided opex of avoided capital expenditure		An adjustment factor has been included to allow for this effect. Refer to Section 2.5.8.
Grid support services		
Network support	Avoided cost of generation from network support facilities; e.g. backup diesel generation	Not material. Refer to Section 6.2
Frequency control ancillary services (FCAS)	Contingency ancillary services (eg responding to large changes in generation and load such as when a large generator trips off)	Excluded on grounds of low materiality with technologies deployed in Victorian DG at the present time and for the forecast period
	Regulation, eg balancing energy supply and demand in real-time and maintaining the grid frequency at 50%	
Network control ancillary services (NCAS)		
System restart ancillary services (SRAS)		
Avoided Transmission Use of System Charges (TUOS)	Similar to that applied to larger embedded generators under Chapter 5 of the NER	Calculated so as to be compared with the network capacity benefits from the economic calculation. Refer to Section 5.4.
Maintain voltage regulation	Cost of maintaining voltage levels	Not material. Refer to Section 6.3
Maintain power quality	Managing harmonics, DC injection and flicker.	Not material. Refer to Section 6.4
Electricity supply risk		
Reduced congestion	Avoided costs associated with congestion applied to energy sourced from constrained networks	This benefit is calculated within the method applied for the network (Network Capacity benefits described above) other than at the 220 and 500 kV transmission levels above terminal station level. This is discussed in Section 6.5
Reducing expected unserved energy (ie improving reliability)	In the analysis, the Value of Customer Reliability defines the value of unserved energy (due to reduced reliability) and this parameter is included in the network capacity calculations. Diversity of generation either geographic or technology, also reduces risk	This benefit is calculated within the method applied.

Benefit	Description	Treatment in this study
Line losses	Power losses on a system with DG are less than on a system without DG, provided the level of penetration is below a given limit (23-50% depending on the system). Losses are already included in the Inquiry's first Phase. DG may produce a secondary losses benefit in enhancing the other calculated network benefits at the network element evaluated when expressed per unit of DG back to the location of the customer.	The additional second-order effect has been considered in the calculation.
Islanding capability / increased customer empowerment – either micro or mini grid level, or facility level	Ability to create a stable island network during a fault. Not yet applicable outside a facility but could be significant at some time in the future.	Not material. Discussed in Section 6.6.

2.3 Scale of augmentation costs by asset class

An important output of the analysis in the previous section is that, of all the benefits assessed, the ones considered to be material are those pertaining to deferral of augmentation capital expenditure ("augex"). This section looks at the scale of augex in each asset class.

The majority of network benefits will be derived from avoided network augmentation expenditure and the related changes in unserved energy that arise. The amount of augex reported by each Victorian distributor is provided below in Table 3. In general, most of the distributors appear to share fairly similar expenditure profiles, with the exception of two unusually large items which are shown shaded in the table. On the assumption that these shaded expenditures are unusual items, and after adjusting the totals for these items, the table indicates that around 43% of expenditure occurs in the sub-transmission system, including switching stations and zone substations, that 24% of expenditure occurs in sub-transmission lines and that the last 33% of expenditure occurs in high voltage (HV) feeders (11%), distribution substations (12%) and low voltage (LV) feeders (8%), with 2% in the 'other' category. Land purchase costs are immaterial at all distribution levels. Note that Table 3 shows only DNSP augex and does not show TNSP augex.

Table 3 Augmentation expenditure for Victorian Distributors, $M2015[4]

Total expenditure Augex	United Energy	AusNet	Jemena	CitiPower	Powercor	Total	Total excluding shaded values	% of adjusted total
Sub-transmission substations, switching stations, zone substations	6.85	14.52	10.35	11.77	6.94	50.44	50.43	43%
Sub-transmission lines	0.85	5.15	0.51	13.67	7.91	28.09	28.09	24%
HV Feeders	1.12	43.55	4.38	3.77	3.17	55.99	12.44	11%
HV Feeders - Land Purchases and Easements	0	0	0	0	0	0	0	0%
Distribution substations	7.50	2.13	1.72	0.97	1.07	13.40	13.39	12%
Distribution substations - land purchases and easements	0	0	0	0	0	0	0	0%
LV feeders	1.87	4.38	2.66	0.26	0.32	9.49	9.49	8%
LV feeders - Land purchases and easements	0	0	0	0	0	0	0	0%
Other assets	0	0	0.38	1.78	22.05	24.21	2.16	2%
Total	**18.19**	**69.73**	**20**	**32.22**	**41.48**	**181.62**	**116**	**100%**

2.4 Method for determining benefits

2.4.1 Economic "with" versus "without" assessment

The annual benefit provided by DG is equivalent to: network costs in a relevant year if distributed generation were not present, less network costs in that year with the distributed generation present and operating in the way it has operated, or could operate (i.e. a counter-factual analysis). Network costs are broadly considered including the amortisation of augex (and the opex on any assets that are or would have been built), and also the value to customers of the change in the risk of unserved energy due to the DG changing the capacity versus load relationship.

The first form of benefit (changed augex) is initially provided to the network owners however in the longer term the amortisation of this augex is passed through to customers via their tariffs. The second form of benefit (changed risk of unserved energy) is provided to customers. The calculation of these benefits mirrors the calculations undertaken by network owners in justifying capital cost expenditure to the regulator.

The assessment of benefit and value should consider all aspects of the network from distribution feeder to transmission level. The geographic granularity of the calculation is based on the zone substation level. This is the smallest geographic element for which data is available. The benefits to other elements of the network such as sub-transmission feeders and transmission terminal stations are mapped to the zone substations they serve for the presentation of results.

This calculation determines aggregated benefit (in dollars per year at each zone substation). The average benefit per MW (or MVA) of distributed generation can be calculated from this aggregated benefit. The benefit attributable to an incremental quantity of DG additional to the existing DG is also be calculated (i.e. the benefit from an additional unit of DG on the network).

The benefits from separate parts of the network are aggregated as described in Equation 1.

[4] Source: 2015 RIN data, Australian Electricity Regulator

Equation 1 Calculation of network area aggregated benefit

$$\text{Network Benefit} = \text{Benefit}_{\text{transmission}} + \text{Benefit}_{\text{Subtransmission}} + \text{Benefit}_{\text{ZSS}} + \text{Benefit}_{\text{Distribution}}$$ [5]

The primary tool proposed for the calculation of benefits is an economic calculation that mimics the main characteristics of the Regulatory Investment Test for Distribution (RIT-D) business assets.

An overview of the process is provided in Figure 7, which shows the calculation for the annual benefit, which equals the savings of customer reliability changes and saved augmentation costs with the DG versus without the DG. The average benefit can be calculated by dividing the annual benefit by the quantum of DG. The incremental benefit can be calculated by adding an extra unit of DG (eg a kW) and calculating the change in annual benefit.

In both situations, the steps and concepts of load duration curves, generation adjustments and other parameters are explained in greater detail in the next Section.

The method requires an estimation of the network costs in each of the “with” and “without” cases. The calculation focusses on the network capacity area which are the costs associated with the capacity of the network and the load upon the network. The costs arise from:

- The costs of augmenting the network to supply the load and
- To the extent that the network at some times cannot supply the load (a probabilistic outcome), there is a cost to customers based on the probability that energy is not supplied to them (referred to as unserved energy). This impact of unserved energy is borne by customers rather than being borne by the network owners and this impact has a notional cost to customers. Because this review considers the benefits to all entities beyond the DG owner, it is important to recognise this as a benefit that can be provided by DG.

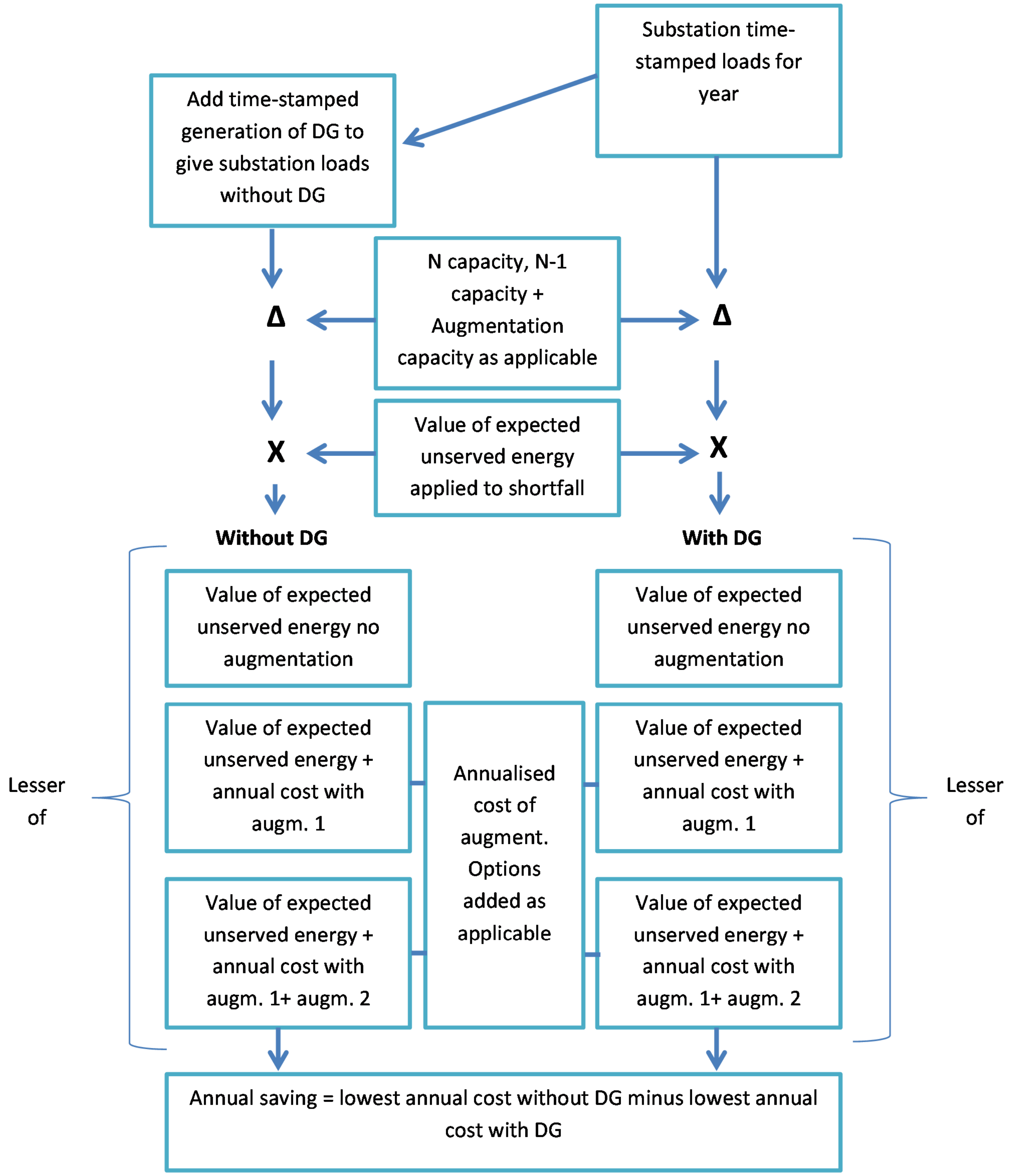
The method requires estimation of the annualised cost of network upgrades where these are avoided or deferred by the DG, which should be annualised using standard asset life assumptions and regulatory real pre-tax WACC (Section 2.5.7). In the same manner as a distributor would evaluate the timing of a network upgrade to justify making an augmentation, the upgrade would, or should, occur at the time when the annual value of expected unserved energy (or customer (lost) reliability) rises to above the annualised cost of the network augmentation.

Accordingly, the costs related to network capacity are the lesser of:

- The reduced expected unserved energy without an upgrade, and
- The annualised cost of the efficient network upgrade option plus the residual value of expected unserved energy that remains after the upgrade

[5] Although $\text{Benefit}_{\text{Distribution}}$ is zero in the results as no reliable method and data have been found to calculate this

Figure 7 Overview of benefits calculation for a given zone substation



In the calculation of the amount of load that would be unserved on a probabilistic basis in a year, it is noted that each substation will have a total supply capacity made up of some number, N, of (for example) transformers. The outcome for a substation in a year can be approximately divided into two parts:

- A probability that all N units are available for supply and
- A probability that N-1 units are available for supply

While there is also a finite probability at substations with more than two transformers that other combinations (N-2, N-3 etc) of transformers will be out of service, the reliability of transformers etc is high enough that the probability of more than one unit being concurrently out of service is low enough to be ignored.

The probabilities of unreliability applied are described in Section 2.5.5. The remaining parameters that are applied are discussed elsewhere in Section 2.5.

This calculation can evaluate the benefit provided in different time-bands by setting the distributed generation quantity to nil in all those time-bands other than the one under evaluation.

The above calculation will estimate the total benefit provided by the embedded generation included in the analysis. This can be done separately for solar PV and other forms of generation to evaluate the influence of the technology characteristics (notably firmness). The calculation can evaluate the incremental value of distributed generation by setting the quantity of distributed generation at the zone substation to 1 MW additional to the total extant distributed generation.

2.4.2 Zone substation data

Data on the distribution network's relevant parameters (loads, configurations) is available for five years from Network Service Provider (NSP) published information. Because the distributors' Annual Planning Reports (APRs) provide projections for five years ahead, a five year period of calculation has been chosen. However, it is likely that the APR data will change each year as circumstances change, so on release of a new APR the projections in (the current) years 2 to 5 will vary. Therefore, while benefits can be calculated for each year of the APR it is anticipated that only benefits for the first year will be used for any firm purpose and the remainder would be indicative.

Providing a projection of the benefit for a period into the future will show stakeholders how the calculated value might change in future as loads change and the network is upgraded, notwithstanding that the future information is inherently less certain than near-term evaluations.

Capacities of substations applied are those listed in the APRs and reflect the current configuration so as to reflect the benefit provided by the existing DG appropriately. In some cases the distributor may already have an augmentation in progress that will be reflected in an increased capacity in a future year. In general, the calculation applied in this review will assess the same timing for the upgrade.

The calculations apply to each zone substation for which data is publically available. As a consequence of this condition, there are a small set of substations where calculations are not made. This is typically because the respective substations predominantly supply specific industries and there are confidentiality restrictions around the publication of relevant energy demand data as needs to be used in the benefits calculations. As many of these industries would be unlikely to implement small scale distributed generation (i.e. < 5 MW) in any case, this is not considered a material issue for this project.

2.4.3 Transmission benefits

Transmission benefits are calculated at the zone substation level. For this purpose the terminal station (TS) predominantly assigned to supply each zone substation is identified. The calculated value of benefits at the terminal station can be then shared back to the zone substations it serves, for example per unit of distributed generation at each zone substation.

The primary calculation of transmission benefits of DG is made using the economic counter-factual calculations using augmentation costs and value of customer reliability using the method described above in Section 2.4.1.

A secondary calculation is made for comparison purposes based on the pass-back of locational TUOS attributable to the distributed generators' operation ("Avoided TUOS") as is provided to larger embedded generators under the NER Chapter 5. The calculation is given in Section 5.4. This Avoided TUOS method is based on an apportioning of transmission tariff costs rather than an evaluation of the costs that would have arisen in the network without the DG and hence is suggested only for comparison purposes.

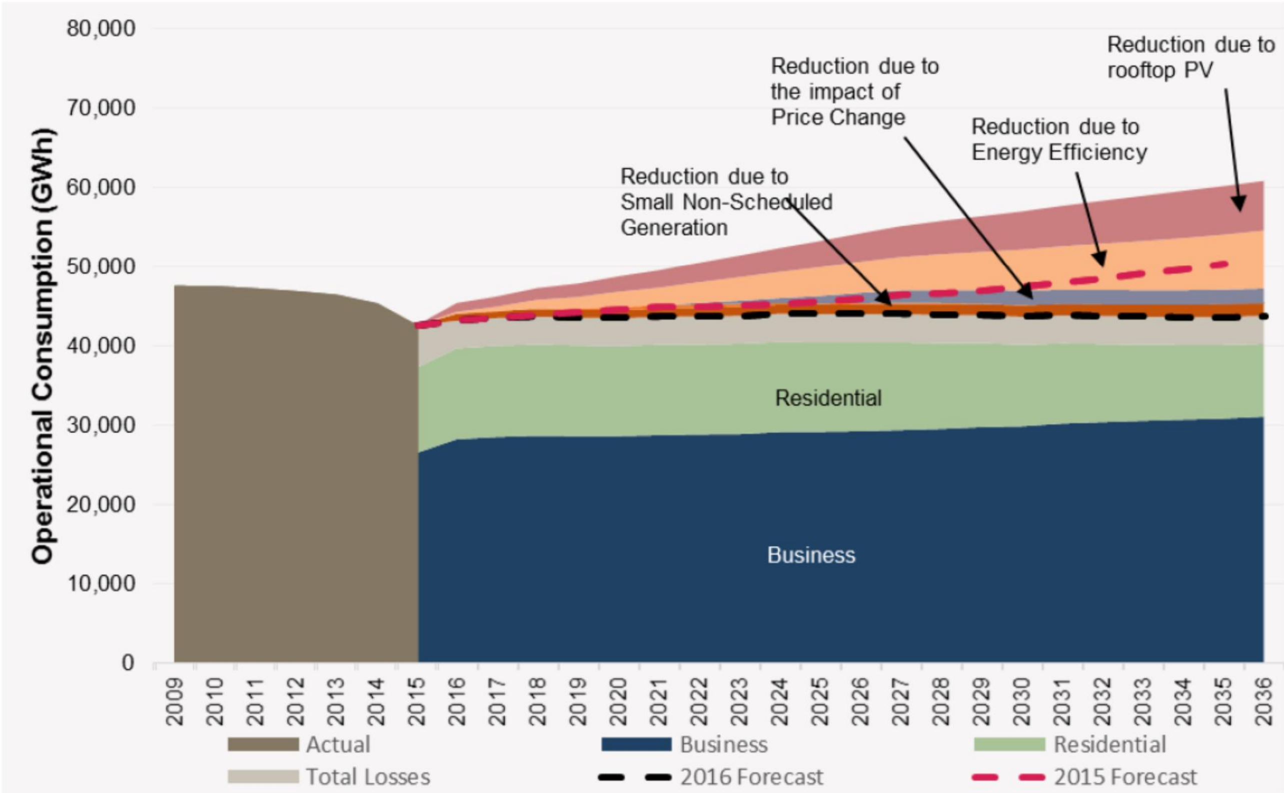
The steps for the economic counter-factual calculation are substantially the same as shown in Figure 7:

- Aggregate the load data for the ZSSs primarily fed by the TS to create the load data for the TS. For example the TS relevant to MDA (Mildura) zone substation is RCTS (Redcliffs), which feeds MDA, RCTS22, MBN (Merbein) and RVL (Robinvale) ZSSs.
- The aggregated load is then scaled to match the Transmission Connection Point Forecasts load. The method also considers the AEMO APR and RIN information for the TS. A 70:30 ratio of the 50%ile and 10%ile load forecasts is applied (refer Section 2.5.4.1)
- Calculate the N and N-1 capacities for the terminal station using the APR and RIN information
- Aggregate the DG quantity based on the DG quantities at the ZSSs primarily fed by the TS
- Calculate the probabilistic values for customer reliability and augmentation costs under the N and N-1 cases similar to the zone substation calculations
- Determine whether the least-cost outcome would be with no augmentation, one augmentation or with two augmentations for each of the “with” and “without” cases and calculate the benefit as the difference in the least-cost outcomes
- Apportion the benefits to the ZSSs fed by the TS according to the amount of DG at each ZSS.

The transmission calculation is only practical at TS level for transformers. The meshed network at transmission level means load flow analysis and additional data would be required to analyse beyond the TS.

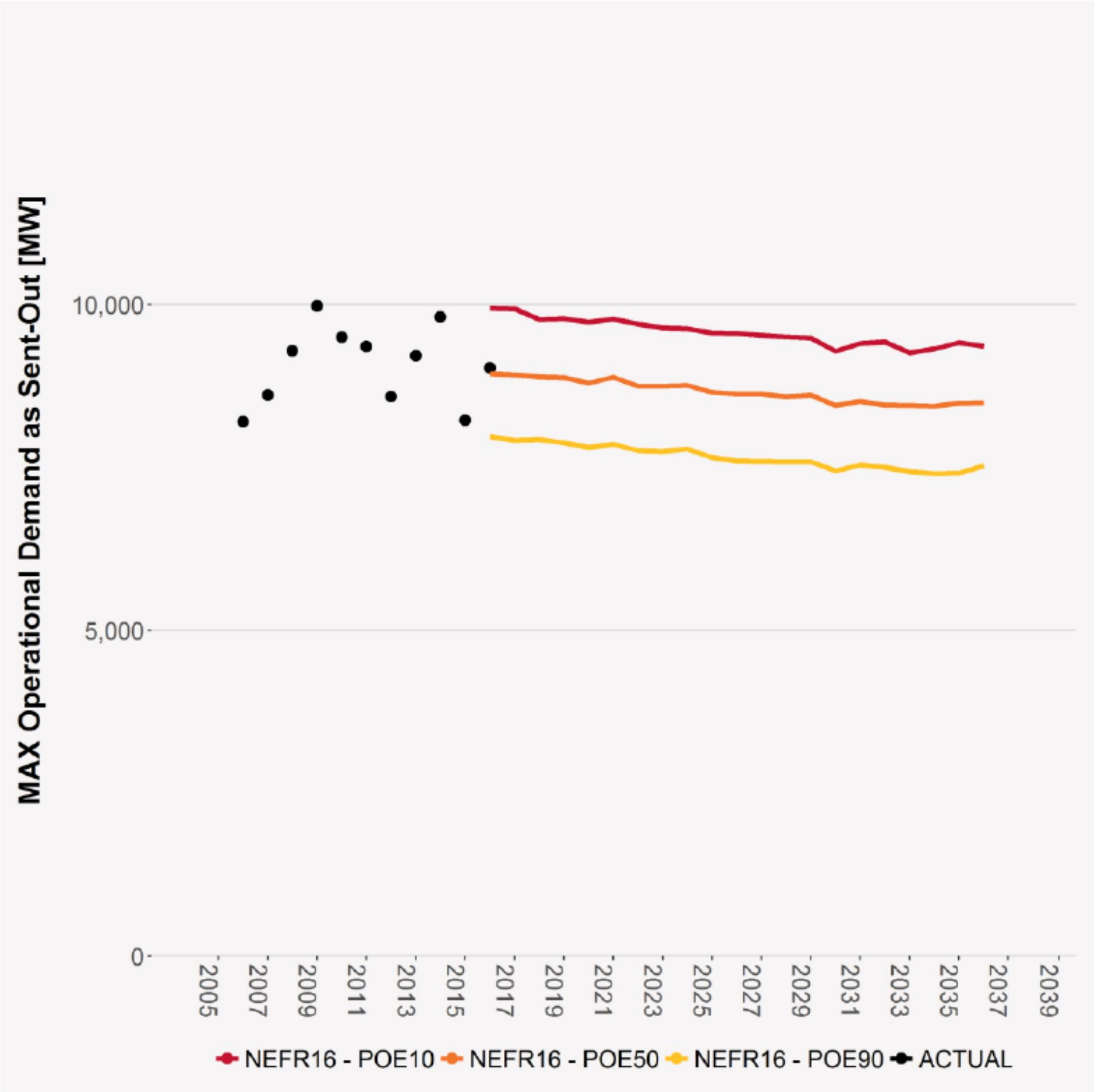
This is not expected to overlook a material amount of benefit provided since augmentation expenditure within the meshed transmission network in Victoria is expected to be low for the foreseeable future due to low load-growth. AusNet (T) reported nil augex in its latest RIN. As at the time of its 2016 APR, AEMO has no open tenders and no active RIT-Ts relating to the Victorian declared network. While part of this low load growth is itself attributable to the presence of DG and the expected further deployment of DG with time, it is also attributable to improved energy efficiency at customer level, a reduction in response to price changes, and a reduction in manufacturing activity in the State. This is illustrated in Figure 8 and Figure 9.

Figure 8 AEMO NEFR Forecast change in Victorian electrical energy consumption[6]



[6] AEMO, "National Electricity Forecasting Report – Chart Pack", June 2016

Figure 9 AEMO NEFR Forecast change in Victorian demand[7]



2.4.4 Sub-transmission feeder benefits

A calculation (economic "with" versus "without" basis) similar to that done for the ZSS analysis has been undertaken using the data from the APRs (typ.). The handling of sub-transmission feeders in the APRs differs between distributors. For some distributors it is possible to evaluate the sub-transmission feeders at a zone substation level and for others it is only possible to evaluate the loop that the zone substation is in. In this second case the evaluation is done for the loop and the benefits apportioned to the ZSSs in the loop proportional to the DG at each ZSS.

2.4.5 Total benefit

The total benefit for all elements of the network are summed at the ZSS level. The benefits are expressed both in terms of the dollar benefit at the relevant network point and also the benefit per unit of DG capacity installed in the relevant network area served, as $/kW.

7 AEMO, "National Electricity Forecasting Report – Chart Pack", June 2016

2.5 Parameters and assumptions used

2.5.1 System configuration and capability

The “with” case reflects the current system configuration and capability. The network has been incrementally built over time reflecting the net loads assessed by the network owners over history.

For the “without” case it would be an impractical task to notionally design from the ground-up what the current network configuration and capability would be had the distributed generation never existed. Given that widespread PV is a relatively recent phenomenon and small, non-PV distributed generation does not have high penetration, it is considered reasonable to assume that the network would look substantially the same in overall arrangement, with relatively minor differences in the number of transformers installed at substations and perhaps a small amount of additional feeders to carry the extra load. The system would however have substantially the same topology as the existing system.

2.5.2 Value of customer reliability

The Value of Customer Reliability (VCR) estimates are available by distributor. The values used by distributors are derived from AEMO VCR values which are different according to the market (residential, commercial and industrial) served by the relevant substation. The state average value for 2015 is $39,500/MWh and most distributors’ values are not very different from this.

Where the split in customer classes is available for a network element such as a ZSS, those splits have been used to calculate a specific VCR for that element. Customer class splits have been provided by the DNSPs.

2.5.3 Discount rate

A discount rate is required for amortisation of capital costs (such as network augmentation costs) over the life of the asset. For calculations of the form used in the counter-factual method a pre-tax real weighted-average-cost-of-capital (WACC) is required. The WACC is derived from the relevant AER distribution determination for each NSP as shown in Table 4:

Table 4 Discount rate (WACC)

Entity	Nominal vanilla WACC	Pre-tax real WACC
Powercor	6.11%	4.79%
CitiPower	6.11%	4.79%
United Energy	6.12%	4.81%
Jemena	6.24%	4.96%
AusNet (distribution)	6.31%	5.05%
AusNet (transmission)	7.87%	7.06%

In converting the nominal vanilla WACC to the pre-tax real WACC an assumed CPI of 2.38% and an effective tax rate of 24% were applied.

2.5.4 Demand

2.5.4.1 General

The approach requires estimation of load duration curves for each substation for the next five years in a business-as-usual world and in a world where the DG did not exist. Load duration curves are commonly used in energy market analyses to understand the amount of energy at risk of not being served. More formally, energy at risk refers to the total energy that may not be supplied when demand exceeds the system capability, including when a critical element such as a transformer or sub-transmission line is unavailable (this is often referred to as an asset's N-1 rating).

The load duration curve is created by sorting demand in each time period from largest to smallest; the y-axis represents the demand expressed in MW or percentage of peak demand, and the x-axis represents the number of hours in the year. They are useful concepts because they allow distribution operators to better understand how the network is being utilised over the year. Steep load duration curves at the maximum demand end require larger amounts of capacity to service a smaller number of hours at peak times and are therefore more expensive systems to run and maintain.

Maximum loads vary according to the weather in the relevant year. Loads are typically normalised to the 50th percentile and the 10th percentile weather outcome. The distributors report different bases in their APRs as described in Table 5.

Table 5 Distributors' descriptions of load percentiles applied in DAPRs[8]

Distributor	Load profile treatment (percentiles of weather outcome)
CitiPower	50%ile
Powercor	50%ile
Jemena	30% weight on the 10%ile and 70% weight on the 50%ile
UE	10%ile for the N case and "a suitable combination of 10%, 50% and 90% PoE" for the N-1 case
AusNet	50% for ZSS and sub-transmission. 10%ile used in discussion regarding distribution feeders

Since the loads that will apply to a particular network location in the future are affected by the weather outcome and hence are probabilistic, the unserved customer energy value (ie the VCR) component of the assessment the calculation that should be applied is the mean (ie expected value) of the benefit provided. Use of the median (50%ile) load (as a proxy for the mean or expected value of the outcome) would understate the benefit as it is likely that the extra benefit provided under a 10%ile load relative to a 50%ile load is greater than the loss of benefit from a 90%ile load relative to the 50%ile load. An assessment using a mixture of the 10%ile (30% weight) and 50%ile (70% weight) outcomes (similar to the APR data for UE or Jemena) has been applied. This matches the approach taken by AEMO in the Victorian Network Planning Approach[9] for transmission and it is understood is the general approach used by Victorian DNSPs.

Where the 10%ile (or 50%ile) case loading is not described in the APRs, an estimate is made using the relative size of the maximum loadings under the 10%ile and 50%ile cases disclosed in the distributors' RIN data.

2.5.4.2 "With" case

The load duration curve under the with case is developed by taking the 2015 actual load duration curve for the ZSS and scaling it to the 50th and/or 10th percentile maximum demand projections in the APR for the relevant year. This provides an approximate normalisation process of the 2015 data.

[8] 2015 Distribution Annual Planning Reports of the respective distributors
[9] http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx

2.5.4.3 “Without” case

The load duration curve for the without case requires development of a load duration curve in which energy generation from distributed sources is added back to the load duration curve from the “with” case.

The task described above is complex because of two issues:

i. ***Coincidence of DG profile and system demand***. Because the generation profile will vary based on technology, climate[10] and seasonal factors, and grid based demand will vary based on timing of appliance usage, the coincidence/correlation of both series will be less 100%. Because the calculation is very sensitive to the net load towards the higher end of the load duration curve it is important to try and estimate the coincident distributed generation output with the system load. There is a requirement to relate time-stamped data of intermittent distributed generation with time-stamped system load for development of the counterfactual load duration curve.

ii. ***DG output generation data.*** The gross generation from DG, not just the export generation levels of DG, provide benefits to networks. This is because the gross output from DG offsets demand that would otherwise be borne by the network. However, small PV metering systems in Victoria predominantly only collect data on exported energy because utilised energy is a behind-the-meter activity (historically feed-in-tariffs tariffs in Victoria have been based on net or exported electricity). It is therefore necessary to estimate gross output energy.

The methods for estimating gross distributed generation outputs are described below.

2.5.4.4 Solar profiles

Solar PV represents the most significant contributor to distributed generation in the network. For the method used, a time-stamped solar gross output is needed for each ZSS in Victoria matched to the time-stamped load on the substation. Since the most complete ZSS load data is based on the 2015 calendar year this is the time-frame desired for the coincident solar data. Note that simulated PV data based on average insolation would not have the time-stamping with actual load that is considered important in this application.

Whereas net solar output is available for samples of customers in each Victorian distribution network there is limited gross data[11].

The following method is applied:

- A single Bureau of Meteorology (BoM) station collecting one-minute solar data remains operational in Victoria in Melbourne. Jacobs has extracted the 2015 data and averaged it to hourly data.
- The coincident dry bulb temperatures for Melbourne have also been obtained from BoM data

[10] PV, the dominant form of DG, is impacted by insolation levels and cloud cover so timing of generation can vary significantly even for neighbouring zone substations

[11] Some would be available from sites such as pvoutput.org however the integrity of the data cannot be checked

- A time-stamped profile of estimated generation from an unshaded, north facing, fixed tilt PV system using typical panel and inverter technologies has been derived by Jacobs using PVSys[12] for 2015 using the BoM insolation and temperature data
- In general, actual PV systems will be a mix of optimally arranged systems as above, and systems with varying degrees of mis-alignment with north, and of tilt, and with varying degrees of shading. Shading would be expected to be worse early and late in the day, and in winter when the sun is lower. To allow for this, data from Ausgrid in NSW has been evaluated. This data represents the time-stamped gross outputs of 300 systems across Ausgrid's area with postcodes attached. By evaluating the average performance of the systems relative to the best performance of the systems a factor can be derived that it is considered reasonable to apply in the present analysis for Victoria.
- Combining the estimated optimum Melbourne PV output with the average performance adjustment factor from the Ausgrid data, a time-stamped gross output profile of average PV in Melbourne per MW can be derived and used for all ZSSs within a small distance (< 50 km) of Melbourne.
- For outside of Melbourne, time-stamped hourly estimated irradiance at ground level has been obtained from BoM covering Victoria based on satellite data on 0.05 degree (approx. 5 km) sized pixels for 2015[13]:

    The Bureau of Meteorology's computer radiation model uses hourly visible images from geostationary meteorological satellites to estimate hourly instantaneous solar global horizontal irradiance (GHI) at ground level.

    For each satellite acquired image, the brightness levels are averaged within each grid cell and used to estimate GHI at the ground. Essentially, the GHI at the ground can be calculated from the GHI at the top of the earth's atmosphere, the amount absorbed in the atmosphere (dependant on the amount of water vapour present), the amount reflected from the surface (surface albedo) and the amount reflected from clouds (cloud albedo).
- For areas outside Melbourne, this data has been used to scale the PV output from the Melbourne example.
- This created a time-stamped PV output profile for all relevant ZSS locations in Victoria
- The quantity of small-scale (< 100 kW) renewable generation is provided on a post-code basis by the Clean Energy Regulator. Additionally the distributors have provided data on the DG quantities (by type) for each relevant ZSS.
- Using the quantity of PV generation estimated to be connected to each sub, and the time-stamped profile of PV output at the location the DG output is calculated
- For projections, scaling the output by the projected total future quantities (capacities) of PV is applied. These projections use the values of PV uptake calculated by Jacobs[14] for AEMO for the 2016 NEFR. The Victorian projections were apportioned to zone substations using the apparent growth in uptake in each zone substation area using PV installation-by-postcode data from the Clean Energy Regulator.

2.5.4.5 Profiles for non-solar generation

The quantity of non-solar DG at each ZSS has been provided by the DNSPs. As noted in Table 1 and Figure 5, of the non-solar DG a small percentage is wind generation. Almost all of the wind generation is connected to Ballarat (North and South) ZSSs. A profile for this generation is taken from AEMO data for the nearby Waubra wind farm.

The balance of the DG is of types that are, or could be, dispatchable. Given appropriate incentives it is expected that these types of DG could operate when called upon.

[12] Proprietary model used by Jacobs
[13] The attribution for this data is that "solar radiation data derived from satellite imagery processed by the Bureau of Meteorology from the Geostationary Meteorological Satellite and MTSAT series operated by Japan Meteorological Agency and from GOES-9 operated by the National Oceanographic & Atmospheric Administration (NOAA) for the Japan Meteorological Agency"
[14] Jacobs report: "Projections of uptake of small scale systems" June 2016 for AEMO (NEFR2016)

2.5.4.6 Hidden distributed generation capacity

There exist in Victoria a large number of generators that presently are not revealed by distributor data but which could potentially be revealed as distributed generators in the future. The main category of these “hidden” plants is the many and various emergency and back-up generators in industrial and commercial facilities around the State. These comprise plants that are often presently not capable of synchronising and may have difficulties with their planning or environmental consents if they attempted to act as distributed generators however it is possible that some could do so given suitable incentives.

It is assumed that this fleet presently do not contribute in any material way to network security and hence they are ignored for the purposes of calculating the existing level of benefit provided.

They should be considered as a potential contributor in the future should the incentives offered warrant.

2.5.5 Calculating energy at risk

Energy at risk is defined as described in Equation 2:

Equation 2 Energy at risk

$$E_{POE10\text{ or }50} = p \times \sum Demand\ above\ N-1\ rated\ capacity + (1-p) \times \sum Demand\ above\ N\ rated\ capacity$$

where:

- $E_{POE10\text{ or }50}$ means the energy at risk for a given probability of exceedance (i.e. 50% or 10% as applicable),
- p means the probability of a major outage, and
- the summations are over the hours in the year

The energy at risk applied is:

$$E_{POE} = 70\% \times E_{POE50} + 30\% \times E_{POE10}$$

Reflecting the weightings discussed in Section 2.5.4.1.

For the probability of a major outage, an individual transformer is taken to have a mean-time-to-failure of 100 years and a mean-time-to-repair of 2.6 months consistent with DNSP assumptions. The resulting annual unreliability per transformer is 0.22%. For sub-transmission feeders the failure rate is taken as 5.1 per 100km/year and a mean-time-to-repair of 8 hours.

2.5.6 Load transfer capabilities

Many ZSSs include a load transfer capability (i.e. transferring load to another ZSS which may have capacity in the event of a failure at the normal ZSS supplying the load).

Jacobs includes this load transfer capability within the analysis of VCR in the N-1 case because it affects the quantity of lost load given that load would actually be transferred on a major outage such as a transformer failure. Load transfer capability is not included in the N case.

2.5.7 Augmentation costs

The annualised cost of augmentations is calculated as:

- Costs per unit of capacity for various upgrade options are determined from the RIN data and from project descriptions within the distributor APRs
- Data is averaged or regressed to develop an average or typical rate for (eg) transformer upgrades
- Typical lives for that type of asset are applied per regulatory submissions

- A pre-tax-real WACC is applied (refer to Section 2.5.3)
- The annualised cost of augmentation is calculated using the above

There are typically two levels of augmentations (beyond no augmentation) included in the calculations. In general, the allowance for the scale of the second level of augmentation in the analysis is such that no further augmentation would be called for in the period to the end of the model (2050).

2.5.8 Avoided opex of avoided capex

An allowance for this has been included in the calculations (at 2%/year of the avoided capex).

2.5.9 Electrical losses

Allowances for loss factor impacts in the energy market have been accounted for in the first phase of the Inquiry.

In expressing the benefits of DG per unit of DG capacity ($/MW or $/kW) it is the DG capacity installed by the customer that is described. One MW of DG operating at the customer location will (in general[15]) have a slightly increased benefit in reducing loadings higher in the network because of the saved losses.

This is managed in the analysis by factoring the DG quantity by a portion of the relevant distribution loss factor when calculating the impacts at ZSS, sub-transmission and TS levels.

2.6 Locations without calculated results

There are 224 zone substation locations in the dataset for Victoria. Benefits cannot however be calculated for a subset of these (or at each level – ZSS, sub-transmission or terminal station) due to data limitations. There are also some locations with naming anomalies or other feature that may impede interpretation of the results. These are summarised in Table 6 along with the treatment applied in the analysis.

Table 6 Locations with data anomalies or other detrimental features

Location	Apparent feature	Notes
Charam	Data missing	No load data is available from DNSP. No calculation is possible
Echuca	No allocation of benefits to hours-of-the-day	Echuca is a particular case where the augmentation would have occurred in 2016 in the absence of the PV. Network benefit is calculated reflecting the deferred augmentation capex however the benefit is not allocated to the hours of the day or any particular day.
Ford North Shore	Data missing	No load data is available from DNSP. No calculation is possible. Most likely due to need to conceal particular customer's load (Ford)
Laverton North 11 kV	Data missing	LVN11 serves a single industrial customer. No load profile is provided.

[15] Up to the point where DG production exceeds the local load which is not expected to be the case within the forecast period.

Location	Apparent feature	Notes
Laverton North 22 kV	Data missing	LVN22 serves the other customers at this ZSS other than the single customer noted for LVN11 above however the DNSP provides a back-up service to that customer under its connection agreement from LVN22. A load profile is provided for this 22kV customer group however Jacobs elected to not calculate benefits at that location due to uncertainty in the treatment of the capacity available
Wemen	The amount of solar PV seems very small for the Wimmera	There is immaterial DG listed at this location in the data
Brunswick	Brunswick appears twice in the ZSS name list	There are two ZSSs in CitiPower that have the name “Brunswick”. They are designated “C” and “BK”. Jacobs retains CitiPower’s naming for consistency with the source data and use the designations rather than the names for most purposes
Bouverie St/Queensberry substation	Data missing	No load data is available from DNSP. No calculation is possible
Fisherman’s Bend	Fishermans Bend appears twice in the ZSS name list	There are two ZSSs in CitiPower that have the name “Fishermans Bend”. They are designated “E” and “FB”. Jacobs retains CitiPower’s naming for consistency with the source data and use the designations rather than the names for most purposes
Laurens Street	Data missing	No load data is available from DNSP. No calculation is possible
Prahran	Data missing	No load data is available from DNSP. No calculation is possible
West Brunswick	Load spike 25 Feb	The load data for WB in 2015 is incomplete.
Westgate	Data missing	No load data is available from DNSP. No calculation is possible
Keysborough	Data missing	No load data is available from DNSP. No calculation is possible. Keysborough is new
Mentone	Data missing	No load data is available from DNSP. No calculation is possible
Springvale/Springvale West		SV and SVW are two separate ZSS but are connected and adjacent. UE considers them together in the APR. SV/SVW serve some critical customers, including Monash Uni and have reserve commitments to some customers. Relative to the load the amount of DG is low however if a calculation was done some energy-at-risk benefit would likely be revealed from FY2018 onwards. Benefits are not calculated at this location because of the more complex arrangement at this ZSS.

Location	Apparent feature	Notes
East Preston (66/22kV)	Data missing	EPN has only just been commissioned (2015). Load data not available
Tullamarine	Data missing	TMA has only just been commissioned (2015). Load data not available
Bayswater	Suspicious load profile 24 Jan	The BWR load data from the DNSP is potentially unreliable
Mt Beauty	Suspect Load Spike (21 Aug)	The MBY load data from the DNSP is potentially unreliable
Murrindindi	Data missing	No load data is available from DNSP. No calculation is possible
Maffra	A 1-hour data gap exists in the load data for the peak day (1 April).	Missing date
Morwell	Data missing	No load data is available from DNSP.
Myrtleford	Spike (5 Jan, 4 am)	The MYT load data from the DNSP is potentially unreliable
Rubicon A	Data missing	No load data is available from DNSP.
Seymour	Spike (15 July)	Unknown cause.
Traralgon	Data missing	No load data is available from DNSP.
Wonthaggi	Load spike (26 Nov)	Unknown cause.
Wangaratta	Load spike (9 Feb)	Unknown cause.

3. Results – value of reducing network congestion

3.1 Introduction

Within the Victorian geographical region, 224 zone substation areas were assessed. The results presented represent the deferral of network augmentation due to distributed generation alleviating network constraints in Victoria and the change in probability of lost-load benefit. The results consider the value of existing and forecasted distributed generation in 2017. The results are summarised by zone substation area in dollars of benefit in the year and in $/kW of benefit in the year (using the connected DG capacity in the relevant area served) and summed for the following asset categories:

- Zone substations
- Sub-transmission feeders
- Terminal stations

Based on the source data from distributors, some data is presented on a calendar year basis and some on a financial year basis. It is not possible to standardise these in this review. Given the other uncertainties in the analysis it is not considered material to the conclusions that some expressions of a value for a particular year may be displaced by six months due to this effect.

The area served by a zone substation (ZSS) was chosen as the analysis area upon which results were expressed. This allows a relatively fine geographic detail to be analysed relative to more aggregated geographic areas. In aggregate and by asset class, the results determined the benefits that exist for the majority of ZSS areas. A small number of ZSS areas could not be calculated (and are shown as having zero value) due to an absence of either load or relevant generation data. The following sections summarise the more material impacts by system type and asset class, where these are calculated to exist. The full set of annual values is available in Appendix B.

Note that in making the calculations, benefits of generator forms (PV vs dispatchable vs wind) are calculated separately and are not generally additive as in some cases they will be providing the same benefit. The combination of benefit may be higher or lower than the sum of benefits depending on the circumstances at the relevant point in the network and is discussed in Section 3.6.

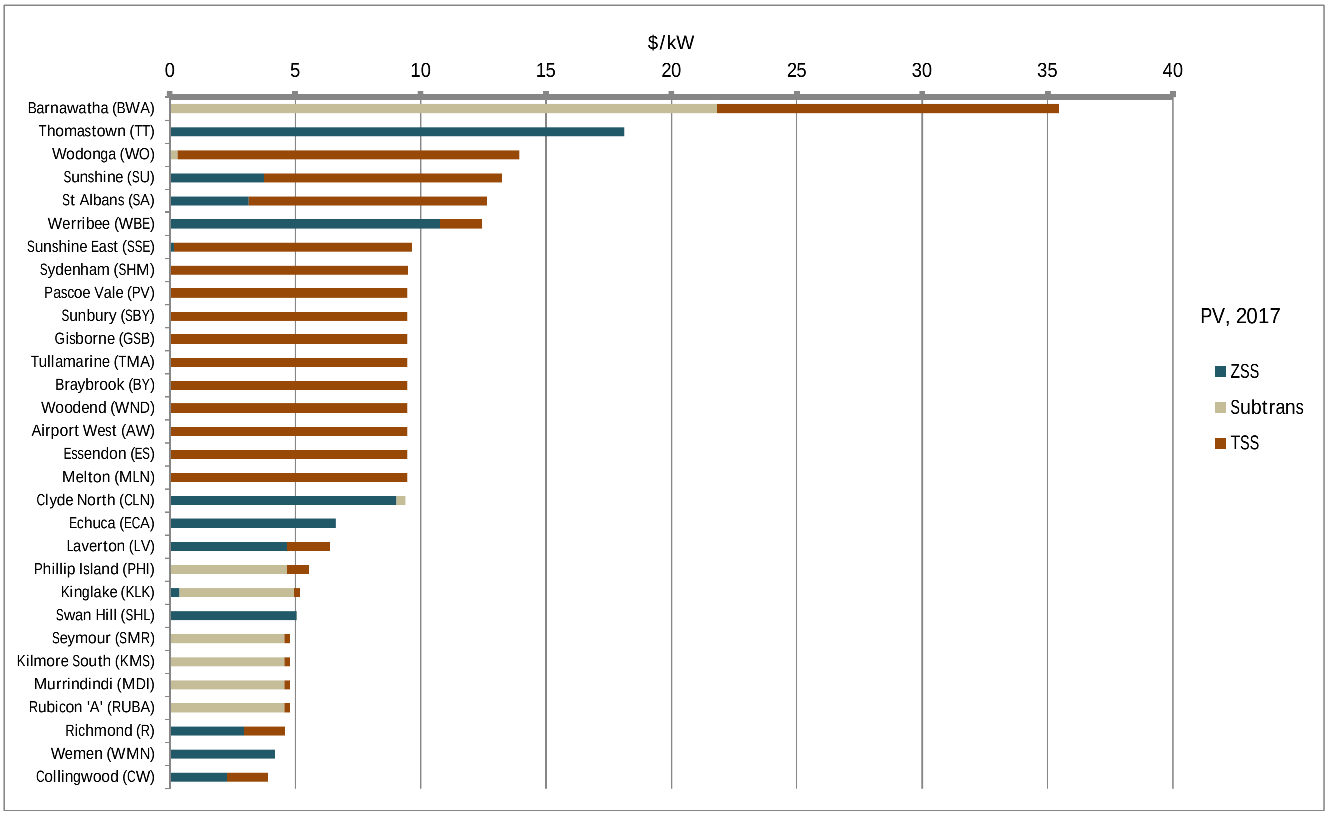
3.2 Solar PV systems

3.2.1 Existing and DNSP forecast solar PV DG benefits

The estimated quantity of PV DG in the Victorian network in 2017 is 1088 MW (nameplate rating).

Figure 10 displays existing and Distribution Network Service Provider (DNSP) forecasted PV system benefits for 2017 by asset class. Benefits exceed $10/kW in six ZSS areas, with 106 of the remaining areas demonstrating a lesser benefit (below $10/kW), and 112 of the remaining areas showing zero benefit. Note that a zero indicated benefit may result from an absence of load profile or solar data for the relevant network elements as well as a calculated zero benefit. A calculated zero benefit would typically result from a network element that has sufficient capacity such that even under the N-1 case and without the DG installed no value of unserved energy risk is indicated.

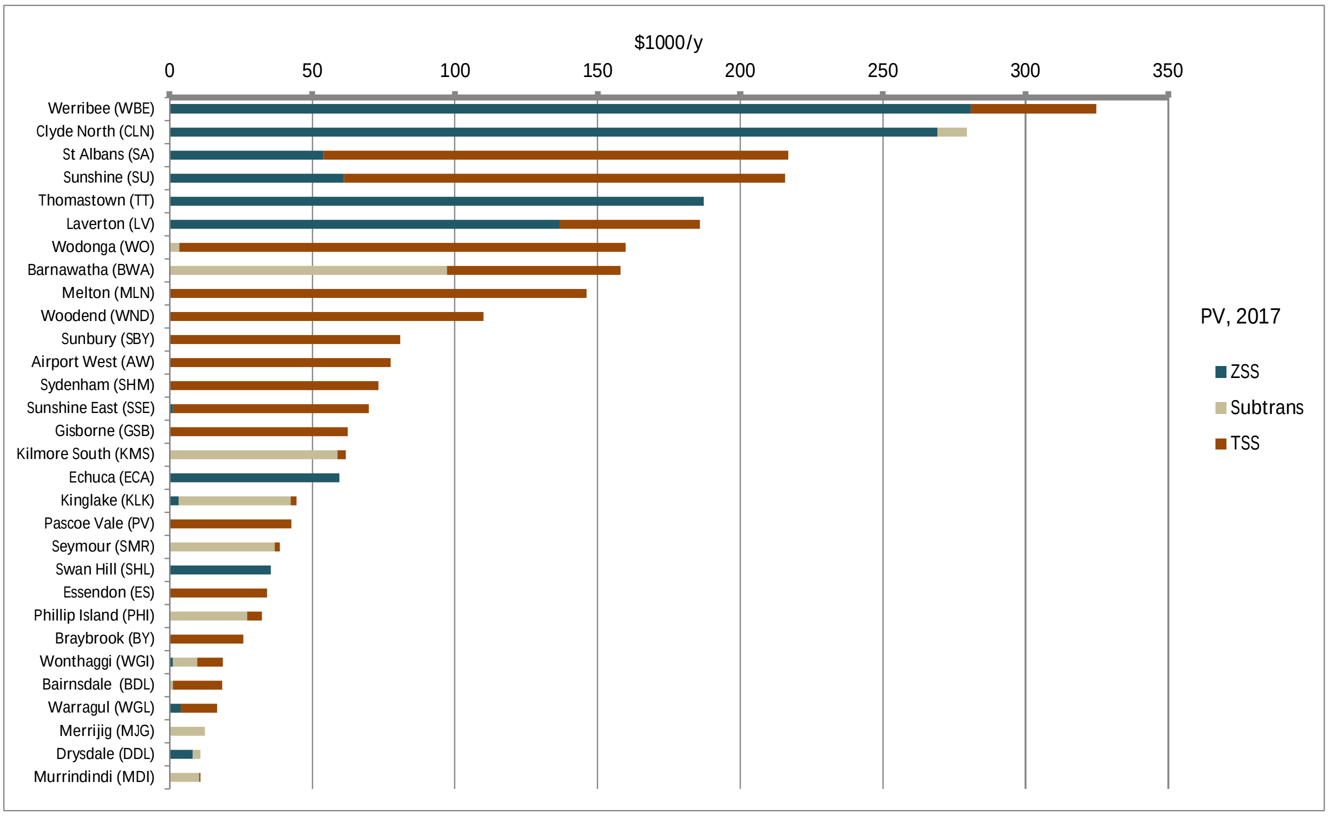
Figure 10 Existing and DNSP forecasted PV system benefits in 2017, $/kW/year



In the ZSS areas where benefit exceeds $10/kW, 21% comes from sub-transmission infrastructure, 45% comes from deferral of terminal station infrastructure, and 34% from deferral of zone substation capital expenditure. The range of assets that could be deferred is quite diverse, implying that PV can defer network investment at all levels of the network.

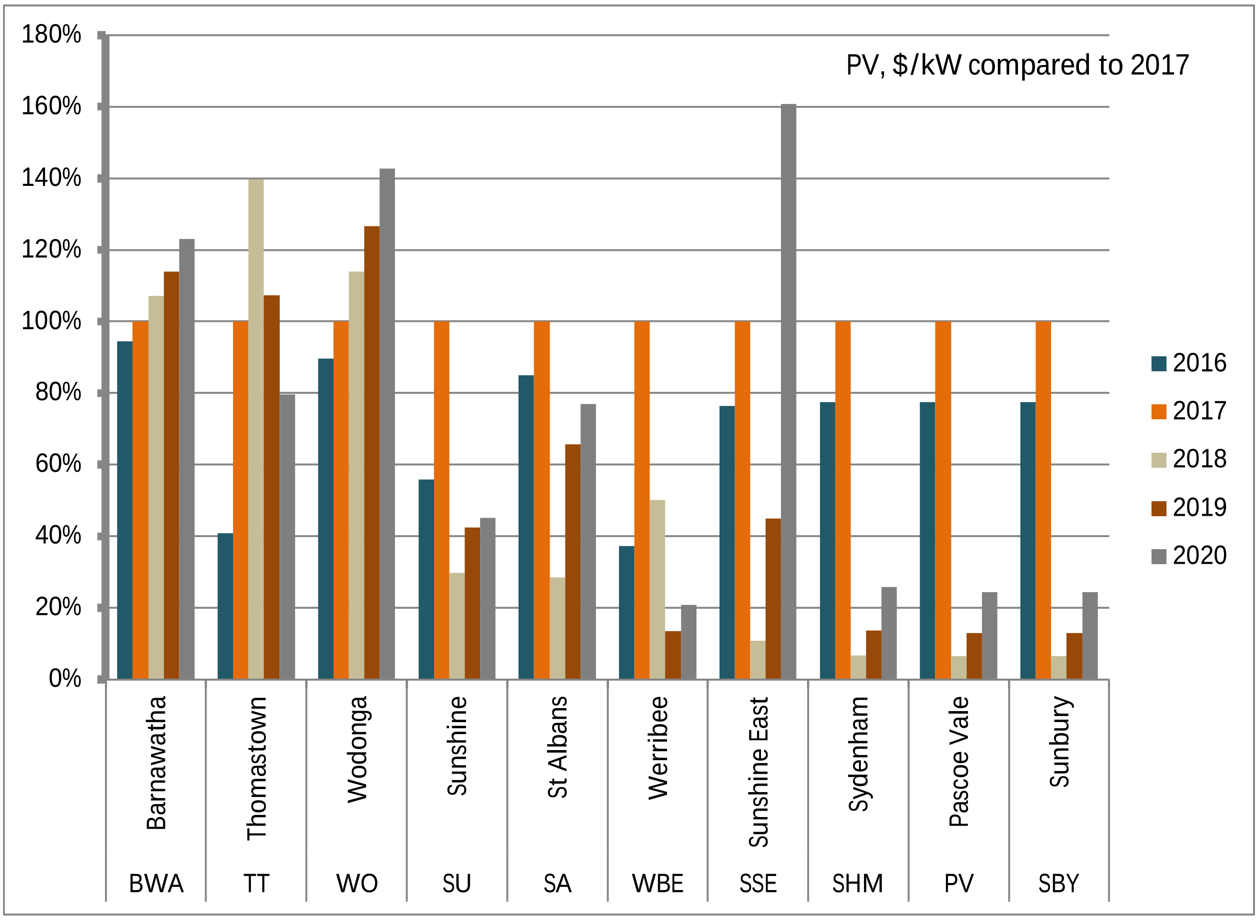
The locations with the highest benefit on an annual value basis are shown in Figure 11.

Figure 11 Existing and DNSP forecasted PV system benefits in 2017, $1000/year



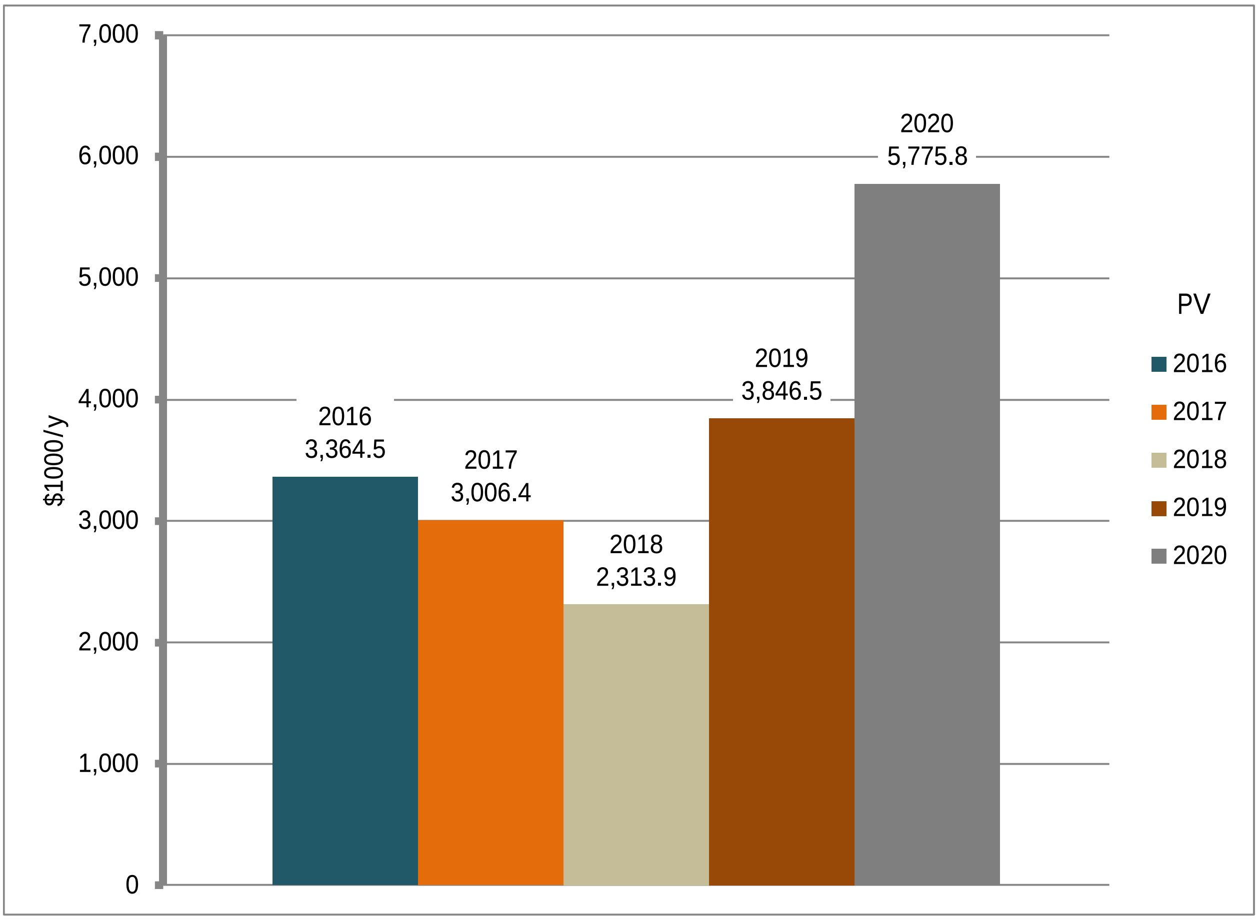
Values can vary significantly from year-to-year. A comparison of values for the highest-benefit locations from 2016 to 2020 (compared with the 2017 value) is shown in Figure 12. Locations can have increasing benefits with time or the benefits can drop-off – typically after an augmentation is undertaken that would be required whether with or without the DG.

Figure 12 Variation of benefit for highest-benefit locations



The total calculated benefit of existing and forecast PV in Victoria in 2017 was $3,006k in 2017 rising to $5776k in 2020 (Figure 13).

Figure 13 Calculated benefits of existing (and forecast) PV in Victoria

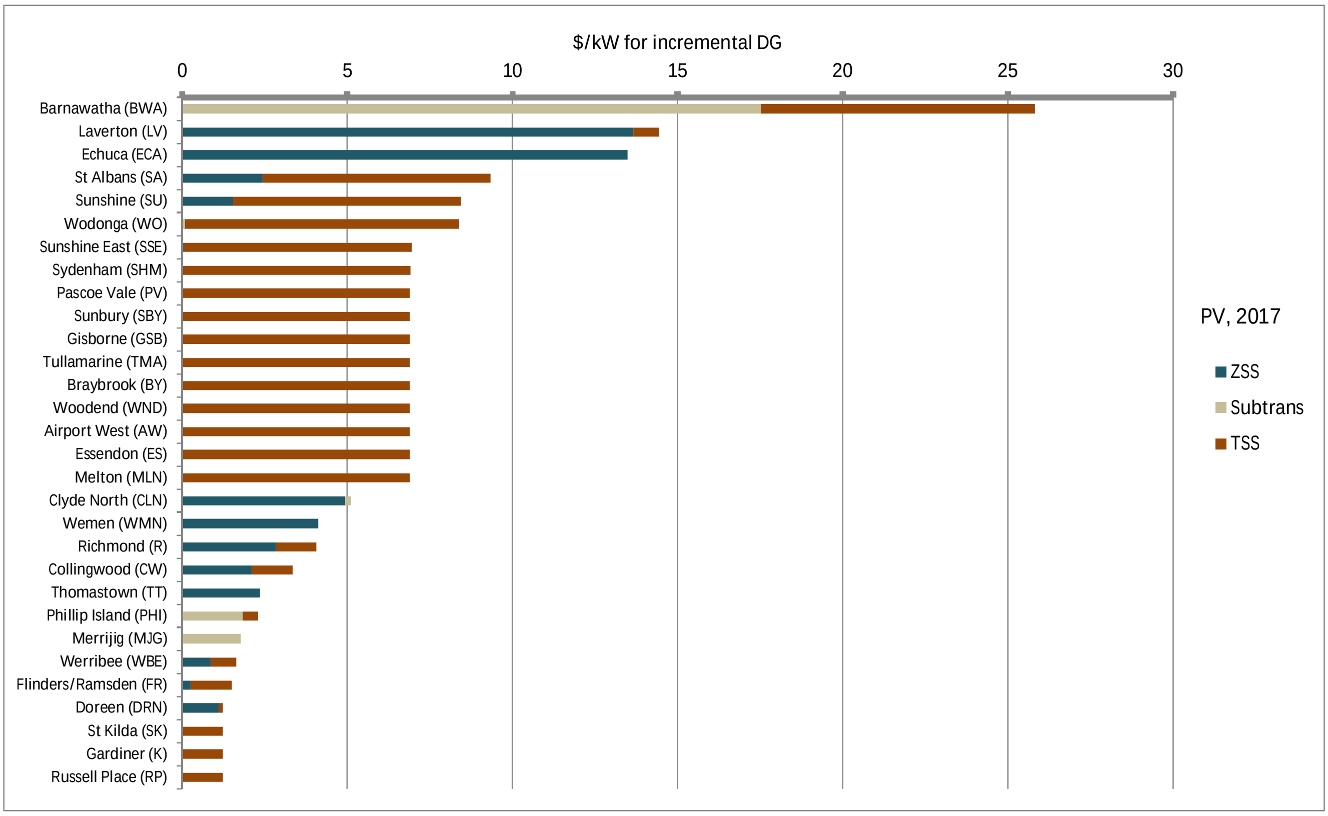


3.2.2 Future incremental PV system benefits

Figure 14 presents benefits for future additional incremental PV capacity. This is PV capacity beyond that incorporated into the AEMO and NSP forecasts based on an increment of 1MW at the relevant locations. Benefits exceed $10/kW in three areas, with 38 areas indicating a benefit between $1/kW and $10/kW.

In the three areas where benefit exceeds $10/kW, 33% comes from deferral of sub-transmission infrastructure, 17% comes from deferral of terminal station infrastructure, and 50% from deferral of zone substation capital expenditure (and change in the value of energy at risk in each case).

Figure 14 Future additional PV system benefits in 2017, $/kW/year



3.2.3 Locational value

Maps showing the locational variations in benefits for existing PV in greater Victoria and the Melbourne metropolitan area are shown in Figure 15 and Figure 16. Additional maps are provided in Appendix B.

Figure 15 Existing PV benefit in 2017, $/year

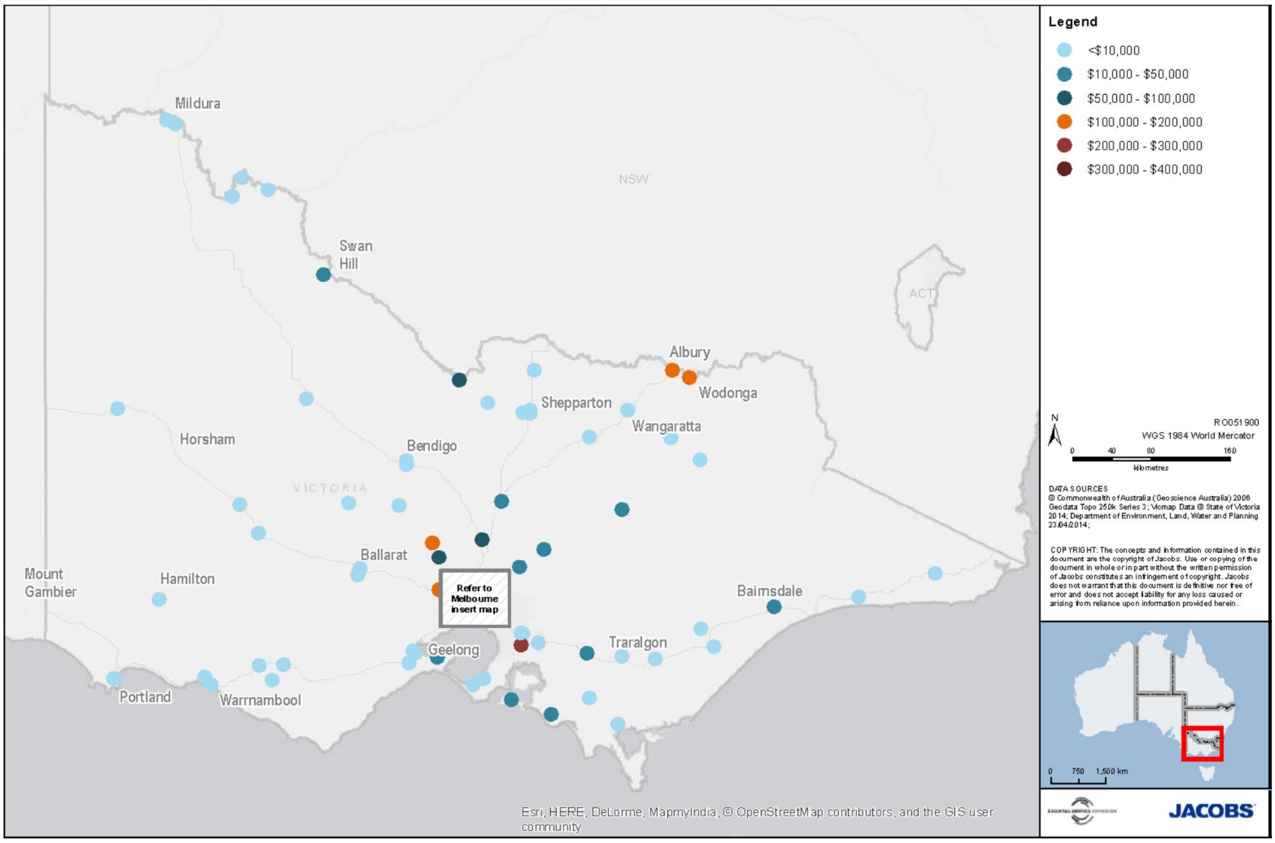
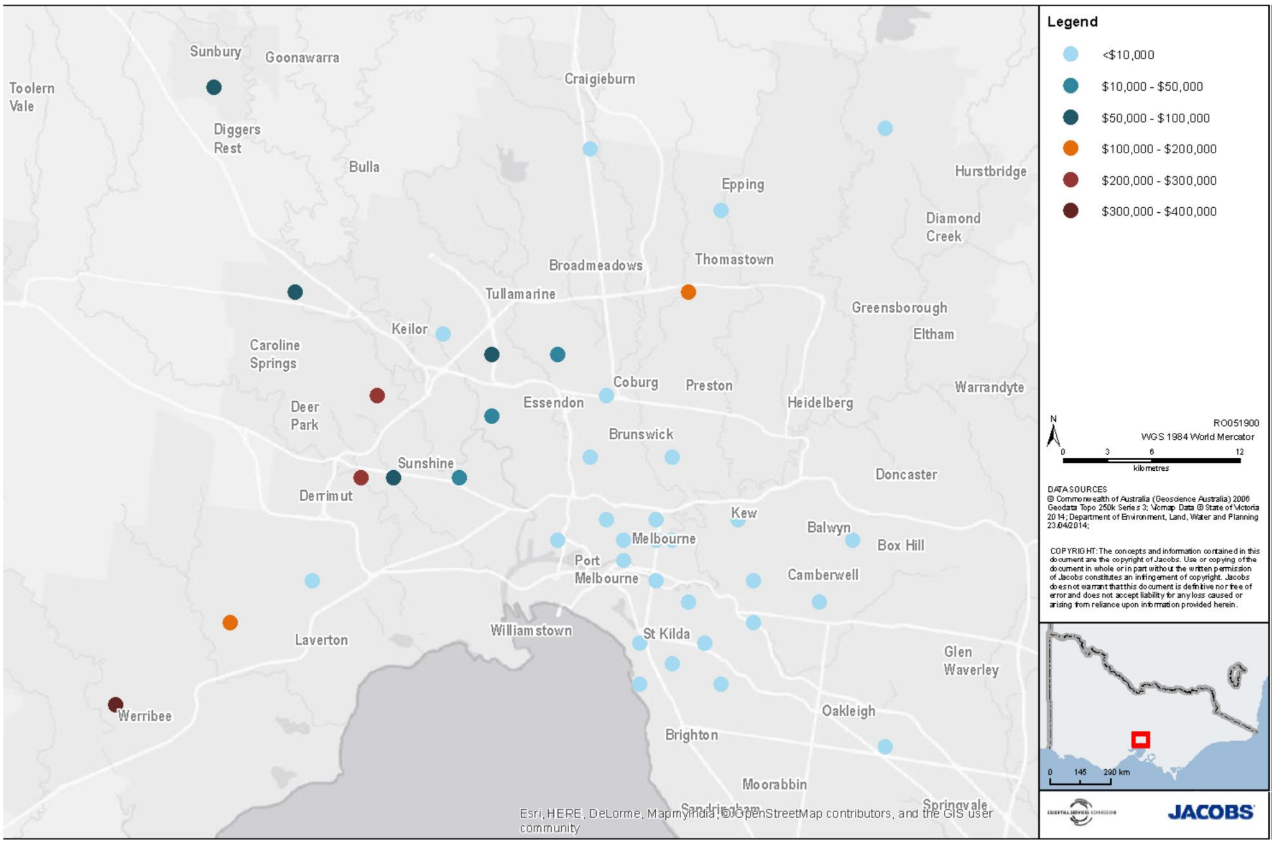


Figure 16 Existing PV benefit in 2017 in Melbourne metropolitan area, $/year



3.3 Dispatchable DG

Dispatchable distributed generation is distinguished from PV in being able to generate on demand at any time of day whether the sun is shining or not. As a result, benefits for this class can occur over a wider range of time periods than is available under PV, and benefits for this class could be considered to be the highest network benefit available to distributed generation.

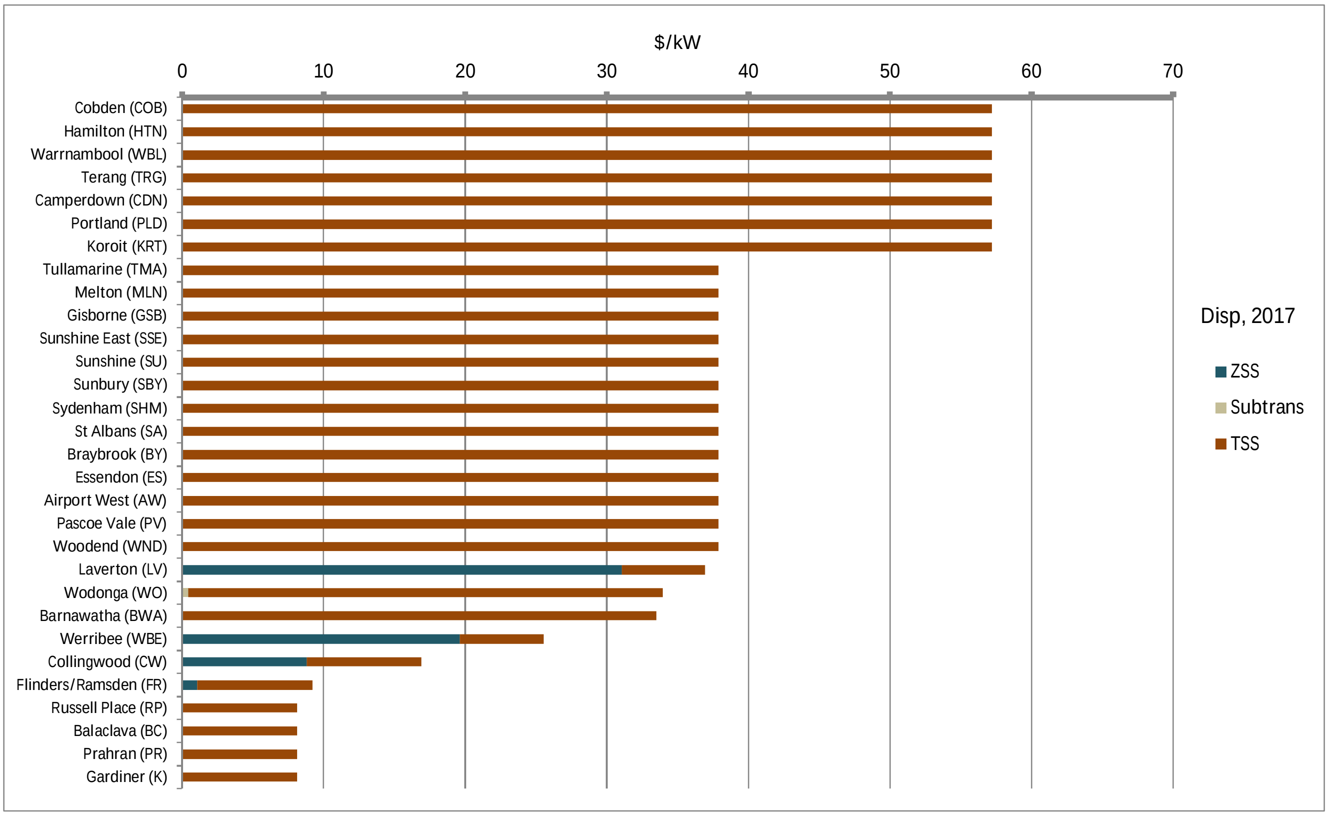
However unlike PV, the actual generation levels of dispatchable DG cannot be reliably estimated at any time of day as the decision as to when the generator operates is generally made by the owner and operator of the generator, and operation of dispatchable generators is not necessarily directed to providing network value. The calculated benefits for dispatchable DG are the maximum benefits that would arise if the operation was directed to maximising value to the network as opposed to being configured to provide some alternative benefit (such as lowest electricity cost to the consumer). The calculated benefits are thus potential benefits that could be available.

3.3.1 Existing and DNSP forecasted system potential benefits

The estimated level of dispatchable DG generation in Victoria in 2017 is 124 MW. There are no estimates of the change in quantity of dispatchable DG over the analysis period other than as already included in the DNSP forecasts (but not separately identifiable) and that Jacobs have modelled (in other work for AEMO[16]) 19 MW of batteries (integrated with PV) in Victoria in 2017.

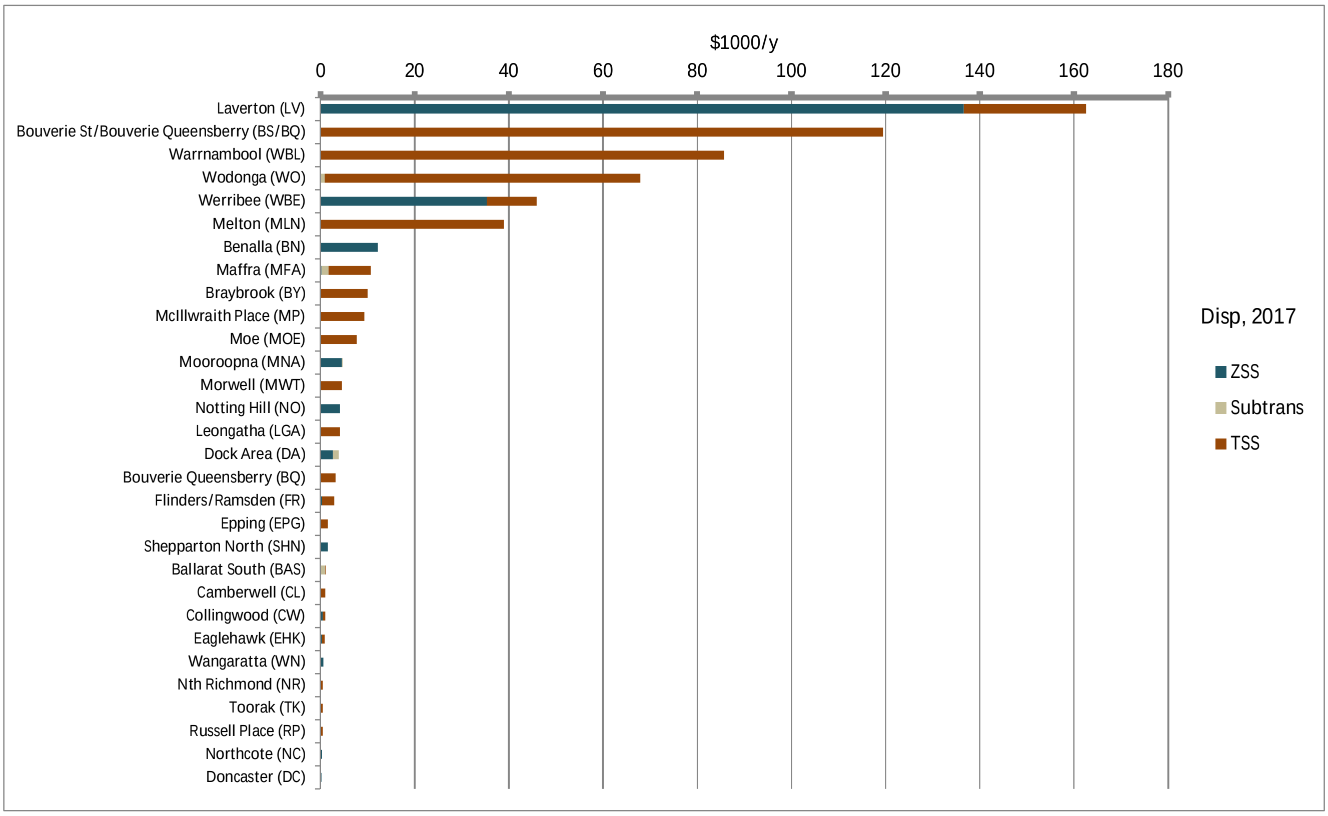
Figure 17 and Figure 18 displays existing dispatchable system calculated potential benefits for 2017. Benefits above $10/kW are present for 25 zone substation areas, compared with 66 areas with benefits of less than $10/kW and 133 areas with zero calculated benefit. In areas where benefits exceed $10/kW, 94% comes from avoided terminal station capital spending and value of customer reliability changes, and 6% comes from avoided zone substation capital expenditure and value of customer reliability changes.

Figure 17 Existing and DNSP forecasted dispatchable system potential benefits in 2017, $/kW/year



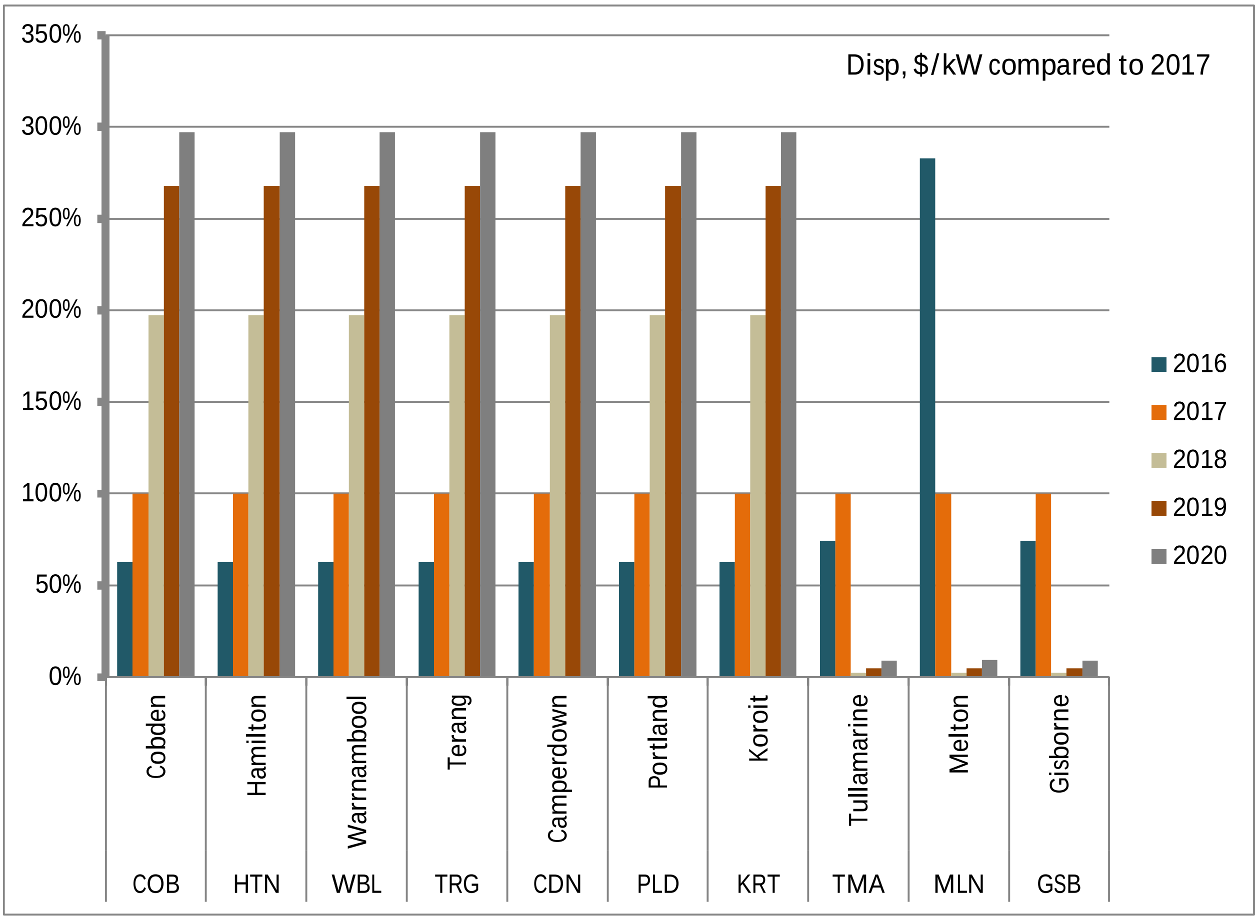
[16] Jacobs report: "Projections of uptake of small scale systems" June 2016 for AEMO (NEFR2016)

Figure 18 Existing and DNSP forecasted dispatchable system potential benefits in 2017, $1000/year



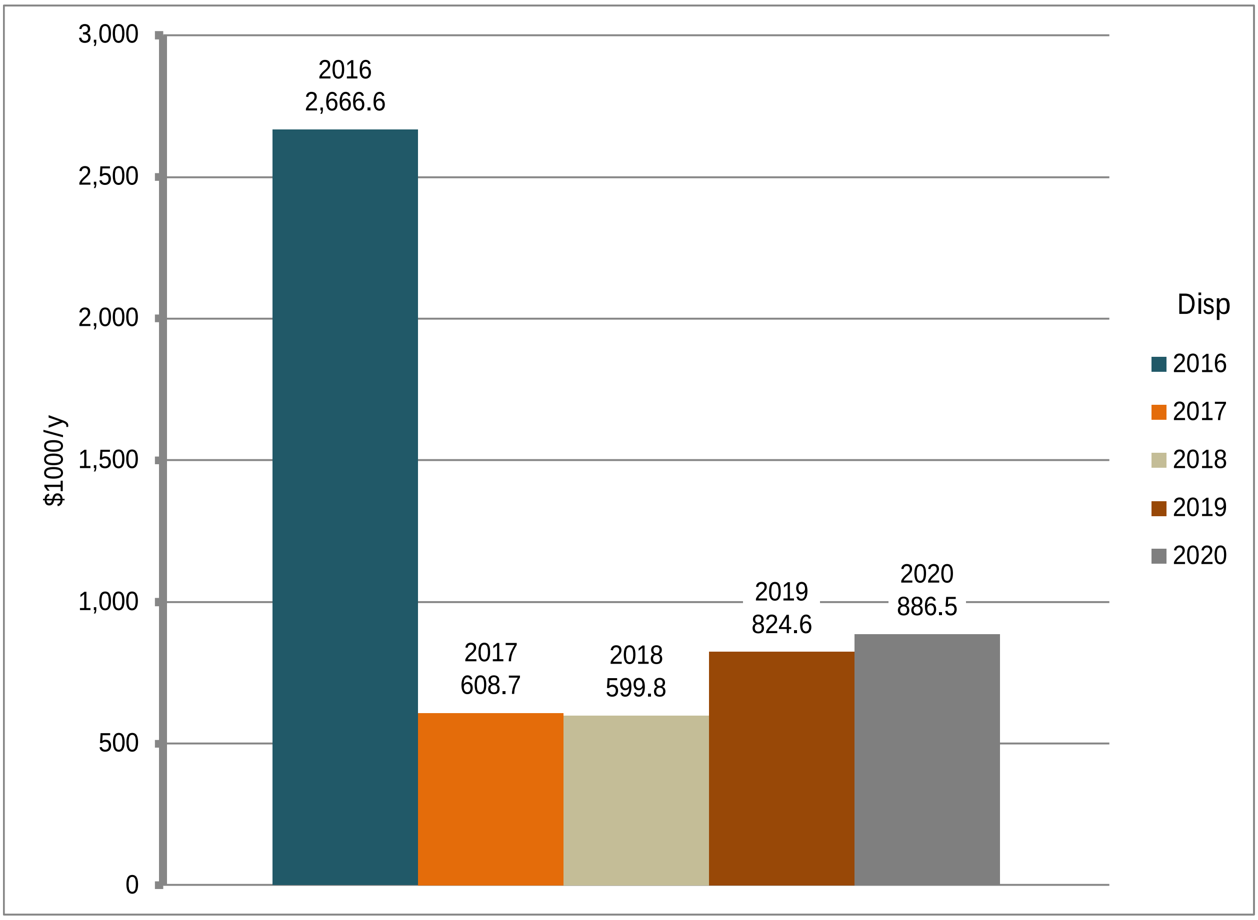
The variation in potential benefit over the period 2016-2020 for the locations with the highest benefit is shown in Figure 19. The results are consistent with the highest benefit locations being serviced by particular transmission terminal stations, particularly in Western Victoria. Where the indicated values are equal (eg Cobden to Koroit in Figure 19) this tends to arise where all the calculated benefits are attributable to the terminal station benefits of a common terminal station as can be seen in Figure 17 above.

Figure 19 Variation of potential benefit for highest-benefit locations



Calculated total potential benefits over the Victorian system in 2017 are $609k (Figure 20). As noted above, dispatchable DG needs to be actually producing its rated output at the time of highest network requirement in order for the benefit to be realised. The values indicated are thus potential benefits and will not necessarily be realised without the operation of the plants being directed to the network need.

Figure 20 Calculated potential benefits of existing dispatchable DG in Victoria

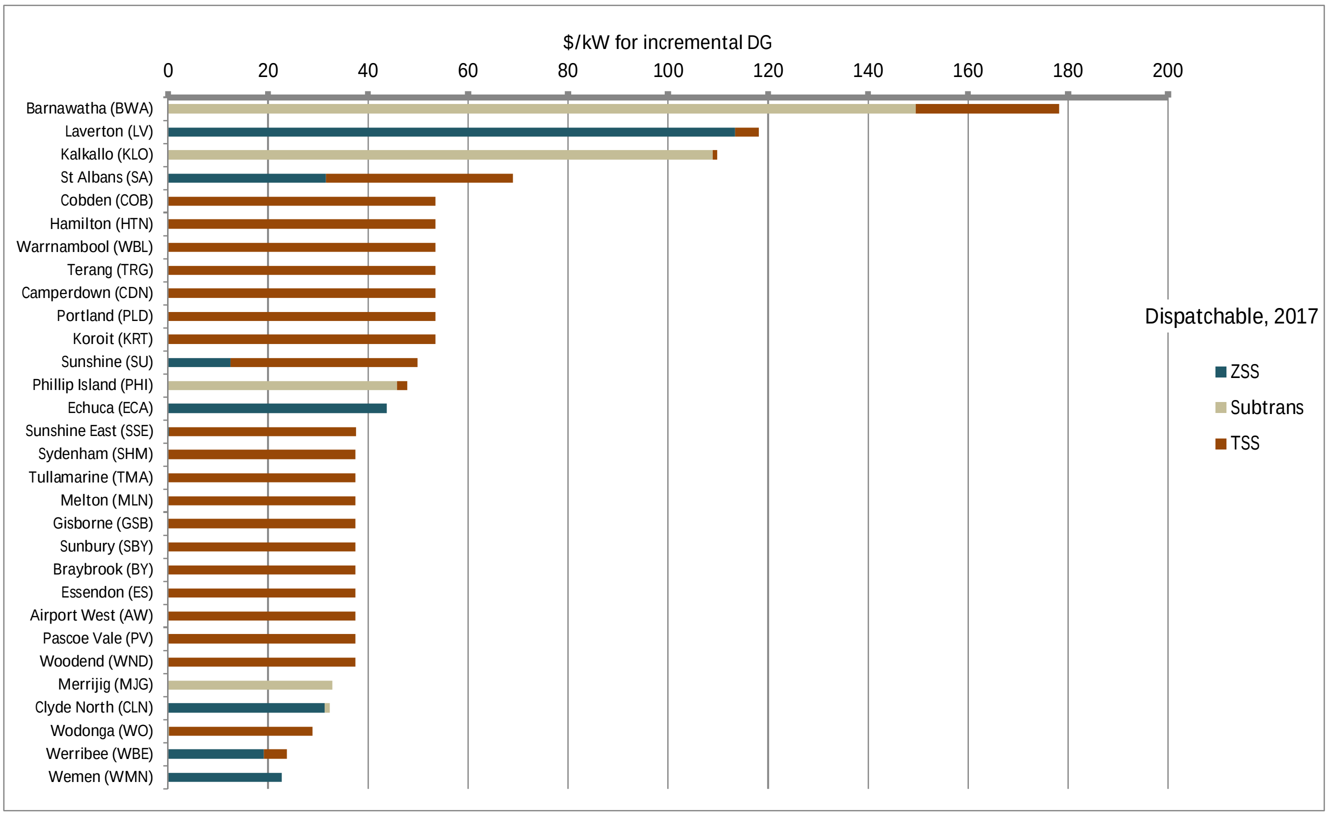


3.3.2 Future system benefits of incremental dispatchable DG capacity

Figure 21 displays additional dispatchable DG system potential benefits for 2017 based on an increment of 1MW at the relevant locations. Benefits above $10/kW are present for 35 zone substation areas, and 48 areas with benefits between $1/kW and $10/kW.

The Barnawatha location has a significantly higher benefit than elsewhere with the benefits principally arising at subtransmission level. At other locations with high calculated benefits the terminal station benefit is generally the more significant. Eleven zone substation areas in particular indicate benefits greater than $50/kW. With the exception of Barnawatha and Kalkallo (both AusNet), these areas all fall in the Powercor distribution area and seven relate to the Terang Terminal Station.

Figure 21 Future additional dispatchable DG system potential benefits in 2017, $/kW/year

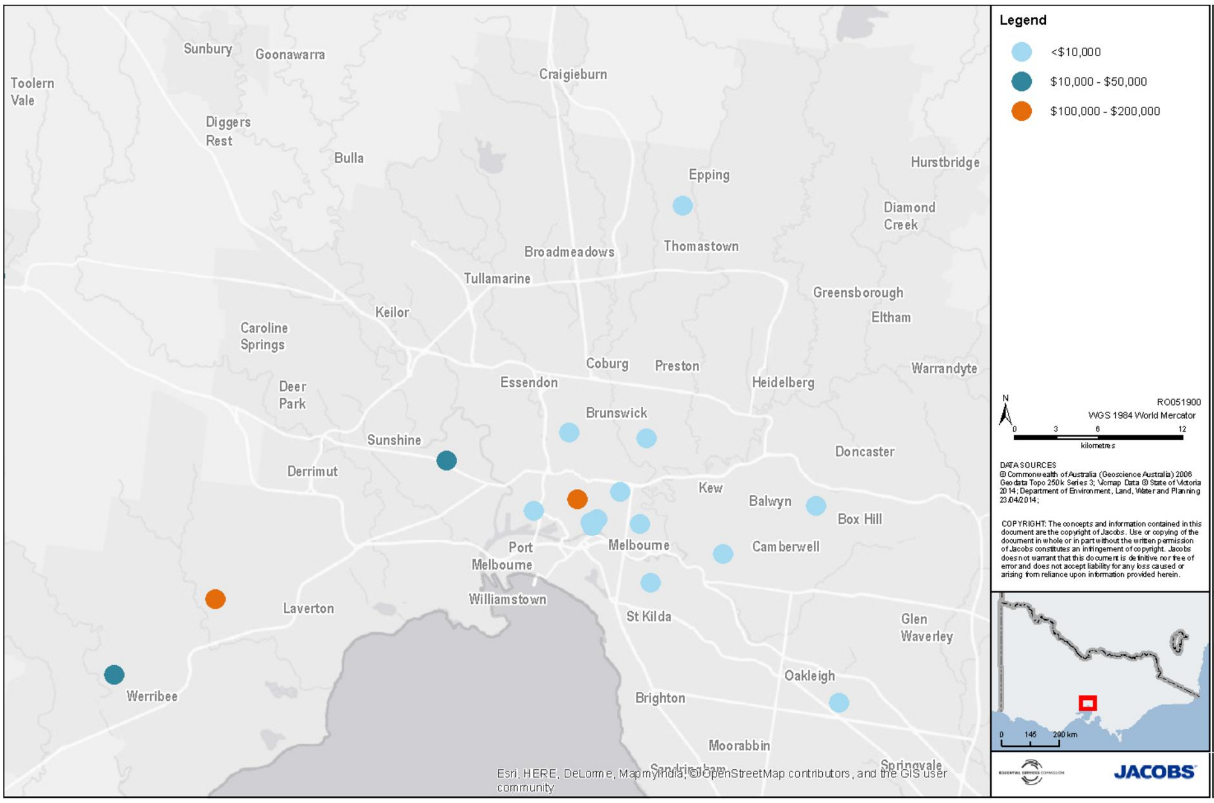


3.3.3 Locational value

Maps showing the locational variations in potential benefits for existing dispatchable DG in greater Victoria and the Melbourne metropolitan area are shown in Figure 22 and Figure 23. Additional maps are provided in Appendix B.

Figure 22 Existing dispatchable generation potential benefit in 2017, $/year

Figure 23 Existing dispatchable generation potential benefit in 2017 in Melbourne metropolitan area, $/year



3.3.4 Comparison of dispatchable DG results with PV results

When comparing the solar values to the dispatchable values, the solar PV values are generally lower on a "per kW" basis. This is because the solar PV systems are only able to generate when the sun is shining and hence do not deliver a large benefit relative to their capacity during later afternoon peak periods when limited insolation levels apply.

This is illustrated in Figure 28 (in Section 3.7), which compares the hourly value of benefit for existing and DNSP forecasted PV and dispatchable DG. In this example, the benefits for existing and DNSP forecasted PV occur at times when the sun is shining and the (potential) benefits for dispatchable generation occur at the later peak periods, notably when PV is limited in delivering such benefit. This is despite Ballarat South having approximately 12 times more PV capacity than dispatchable generation (on a nameplate basis).

3.4 Wind systems

Only Ballarat North and South ZSSs have a material amount of small wind capacity (4.1 and 6.15 MW respectively). Three other ZSSs have immaterial quantities of small wind (< 0.2 MW each). No separate benefit value has been calculated except Jacobs has analysed a case with all DG present (PV, dispatchable and wind) to estimate an overall value.

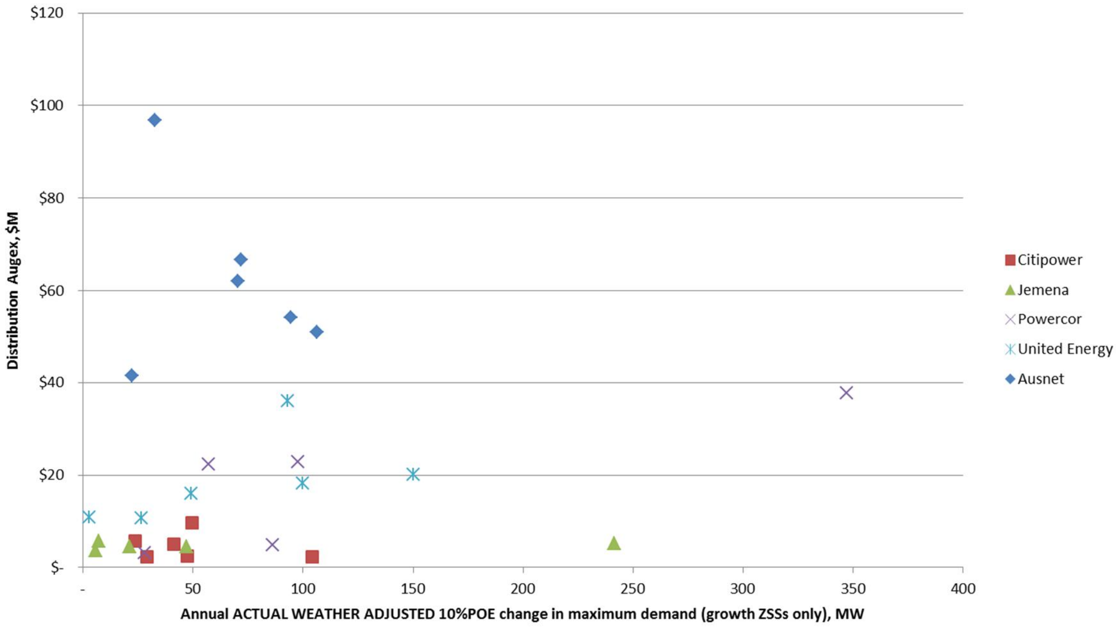
For this "All DG" calculation the generation profiles for the small wind generators near Ballarat have been taken from the 2015 generation profiles for Waubra WF (30 km from Ballarat) using AEMO data.

3.5 Distribution benefits

No network benefit has been ascribed to distribution level benefits below ZSS level as no method has been found to reliably estimate the benefits at this level, though it is considered that some level of benefit will exist.

The level of data available for the previous asset classes (ZSS, terminal stations and sub-transmission feeders) was not available to model distribution benefits of distributed generation. Jacobs reviewed the relationship between distribution augmentation expenditure (Augex) and peak capacity instead, to attempt to derive a relationship between the two that might be usable to understand network value of avoided peak demand. The results are summarised in Figure 24.

Figure 24 Relationship between augmentation expenditure and the sum of non-coincident, growth based, 10PoE demand[17]



Understanding the relationship between distribution augmentation expenditure and change in peak demand for a regression analysis is problematic for a number of reasons:

i. Some augmentation is geographical, rather than capacity based. Where this occurs, it is likely that a significant portion of augmentation expenditure would be required in any case, including poles and wires, and that the presence of distributed generation is likely to do little to reduce it.

ii. A portion of augmentation expenditure may be due to increasing safety or control systems which would be needed in any case and is therefore independent of capacity levels; this could occur in areas where there has been decline in demand.

iii. The presence of a small number of extreme values would unduly influence any regression model derived from such data, leading to uncertainty around the robustness of the results if too reliant on individual instances of expenditure which might incorporate the previous deficiencies.

Given the reasons above, estimating distribution benefits using a regression approach with the available data may not provide results with reasonable levels of confidence, hence regression modelling was not pursued further. Jacobs' attended a stakeholder workshop with the distributors and determined that, while the distributors have access to a greater amount of detail, it is not arranged and stored in a manner that would be readily accessible and it would not be possible in the time available to derive the required level of information to support the Inquiry.

Consequently Jacobs have not included a value for benefits derived in the distribution system below ZSS level in the analysis. The DG benefit presented will accordingly understate the level of benefit from DG as in some cases the DG will be deferring some augmentation cost on this area of the network.

Table 3 in Section 2.3 above presents a breakdown of DNSP augmentation costs by distributor. The data indicates that DNSPs continue to have expenditure at the distribution level and Jacobs expects that most of the potential benefits below ZSS level would be based on avoiding or deferring distribution transformer upgrades. Other distribution level elements (HV feeders, 415V) are expected to be configured (and hence cost) substantially the same with or without DG and be less sensitive to load changes within an area already served.

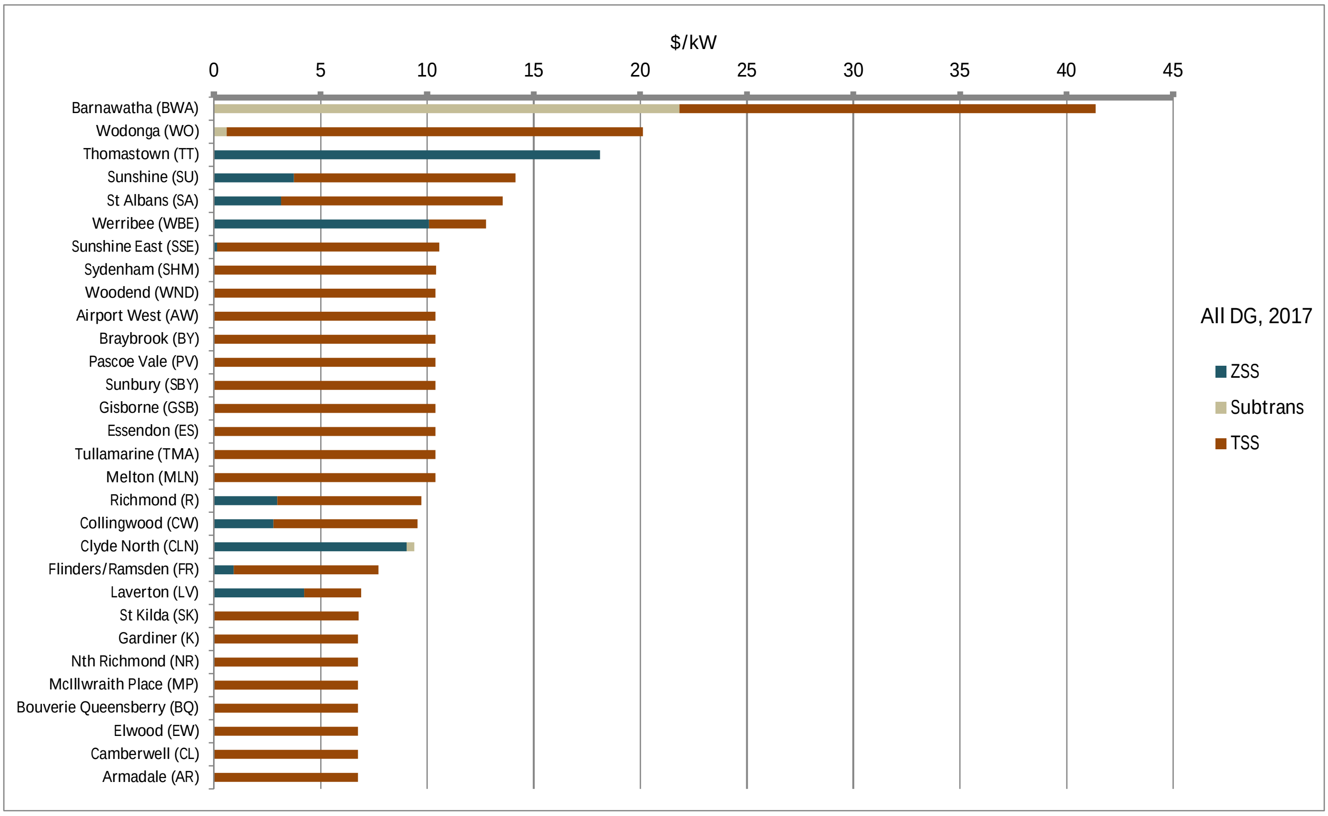
[17] Source: Jacobs' analysis of RIN statements published by the AER from 2009 to 2015. Note that augex is plotted against change in peak demand for substations where that change has been positive (i.e. exhibiting growth). Values are provided in $2015.

3.6 All-DG benefits

The analyses above consider the benefits of PV and dispatchable generation separately.

The benefits of the combined existing DG (PV plus dispatchable plus wind[18]) are shown in Figure 25, Figure 26 and Figure 27. Since the dispatchable DG benefits can only be described as potential benefits, the combined benefit calculated will also be a potential benefit.

Figure 25 Existing and DNSP forecasted total DG system potential benefits in 2017, $/kW/year



Because of the much larger quantity of PV generation than dispatchable DG and wind DG, the values on a $/kW basis in Figure 25 are similar in form to the PV benefits. On an aggregated value per year basis (Figure 26) the benefit is generally slightly more than the sum of the benefits of the individual technologies. The total calculated potential benefit in 2017 for all DG is $3,762k/y whereas the sum of the value of PV plus dispatchable generation in 2017 is $3,615k/y. Some locations have a higher aggregated value and some lower.

[18] Though wind DG is very limited in Victoria (Section 3.4)

Figure 26 Existing and DNSP forecasted all-DG system potential benefits in 2017, $1000/year

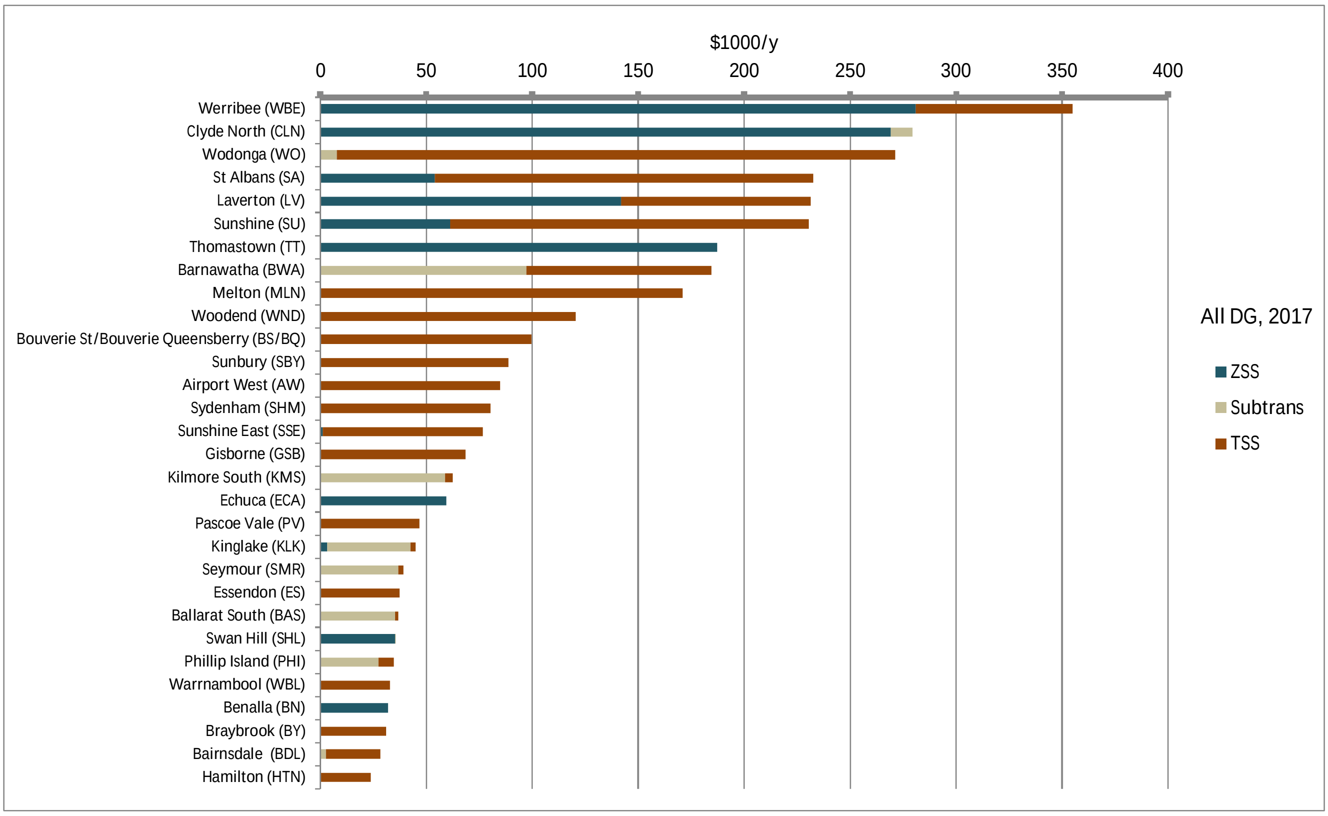
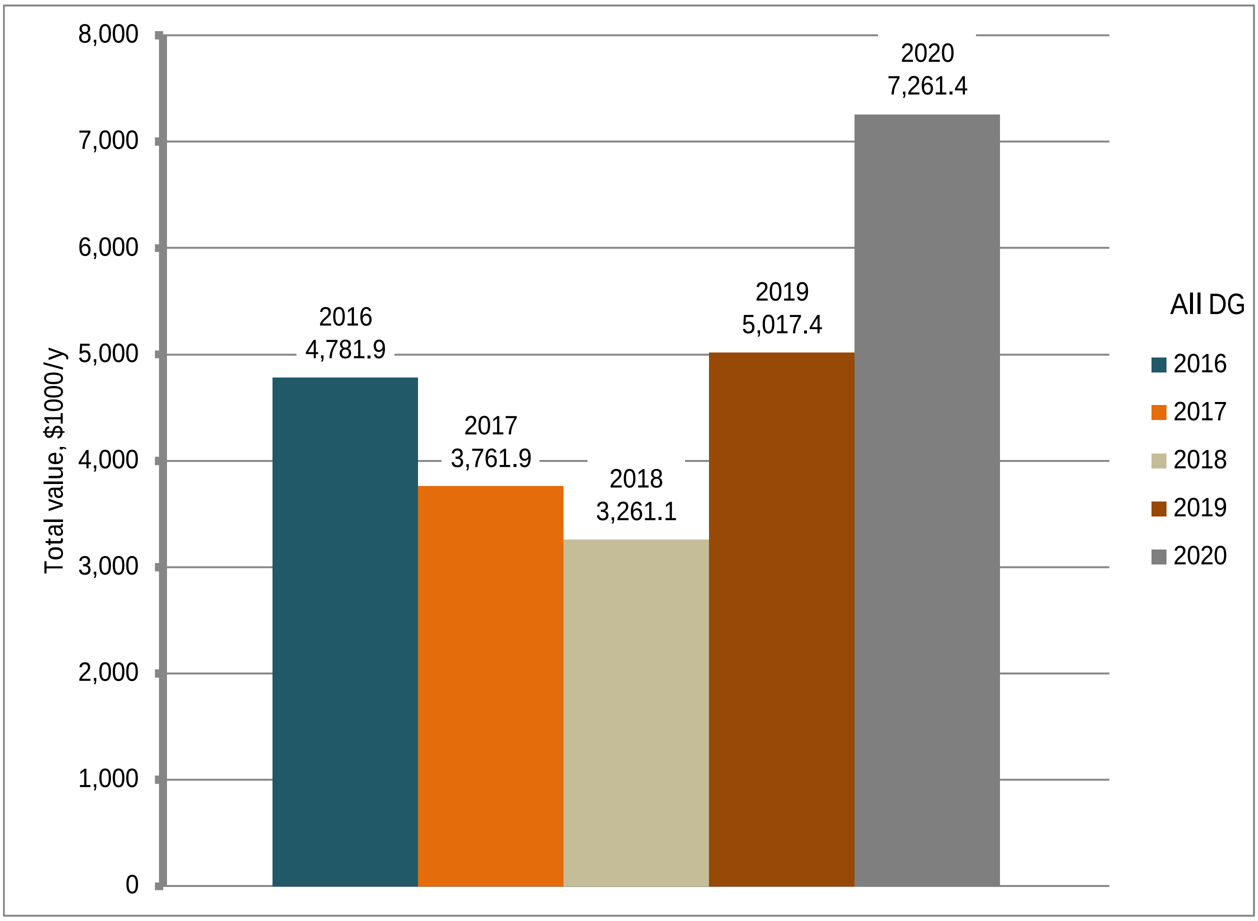


Figure 27 Calculated benefits of existing all-DG DG in Victoria



The form of the change in aggregated value per year over the period to 2020 (Figure 27) is similar to that of the PV technology (Figure 13).

3.7 The time-of-day dependence of benefit

Hourly values shown are calculated by (in turn) applying only the distributed generator output for that hour of the day and setting other hourly outputs to nil. Accordingly augmentation will be unlikely to be triggered based on the applied method, and the hourly values substantially reflect only the probabilistic value of unserved energy saved by the distributed generator operating in that time period. Since the sum of these values will in general exceed the total calculated value (which may have been abated by having done augmentations), values are calculated as percentages intending to reflect the sharing of total value over the periods within a day.

The Werribee location has the highest value for existing PV and a relatively high value for dispatchable DG. The allocation of benefits to the time-of-day overlain on the maximum day loads for the substation are shown in Figure 28 (PV) and Figure 29 (dispatchable). The benefits of the dispatchable generation are more aligned with the time of day that the maximum load actually occurs whereas the time-of-day of the PV benefit is impacted by the daily profile of PV generation, which is relatively low at the time of the daily maximum (6 pm). Because the quantity of PV is greater than of dispatchable generation it is also creating some benefits earlier in the afternoon when the load would be relatively higher but for the presence of the PV.

Figure 28 Hourly benefit spread – Werribee PV

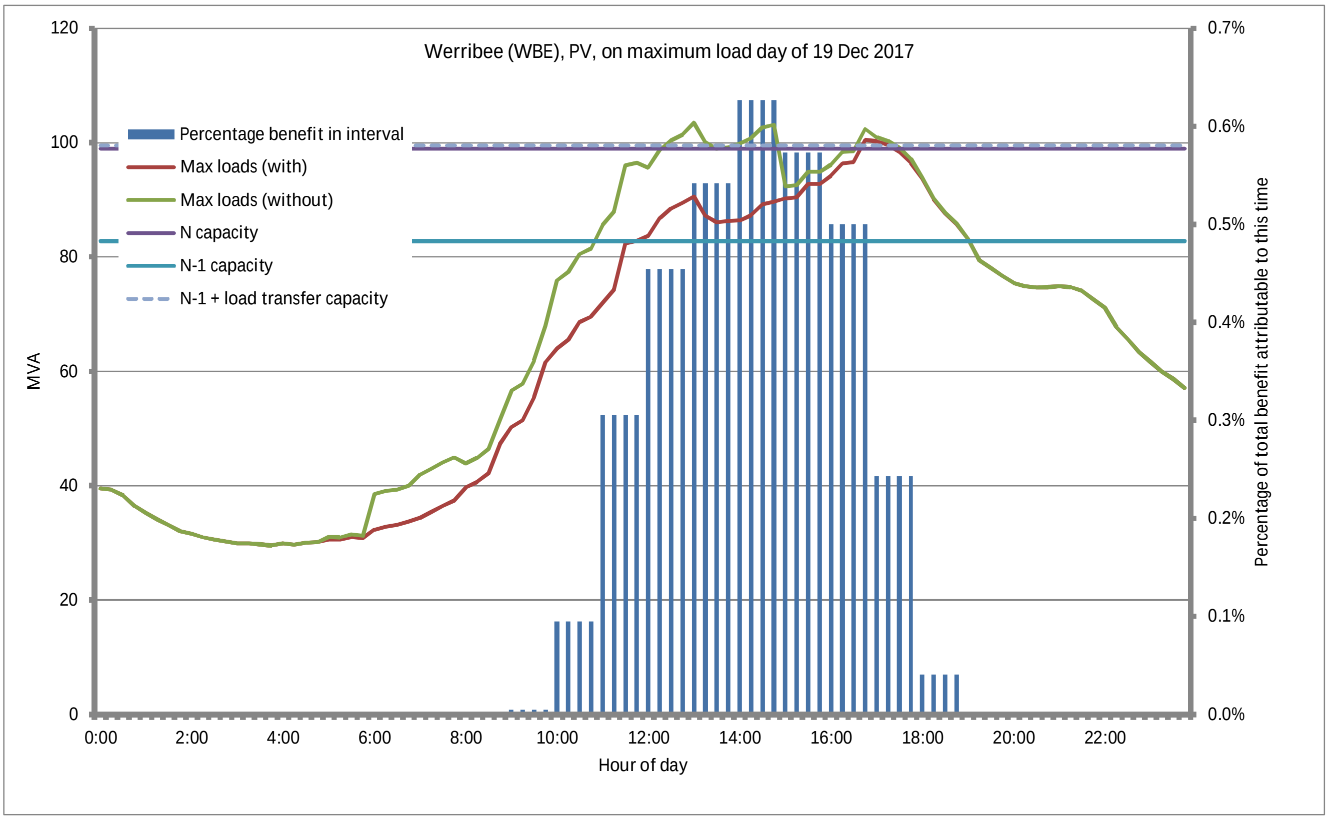
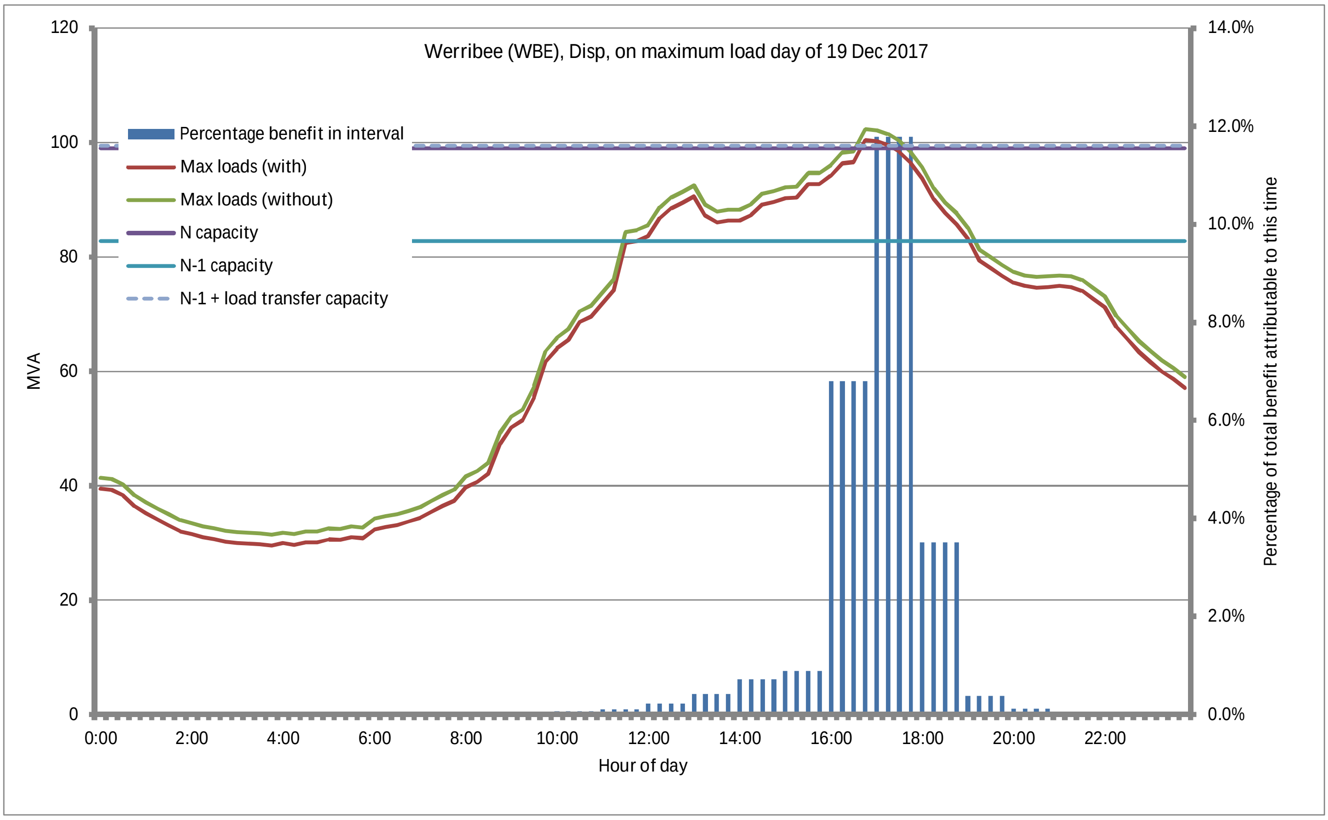
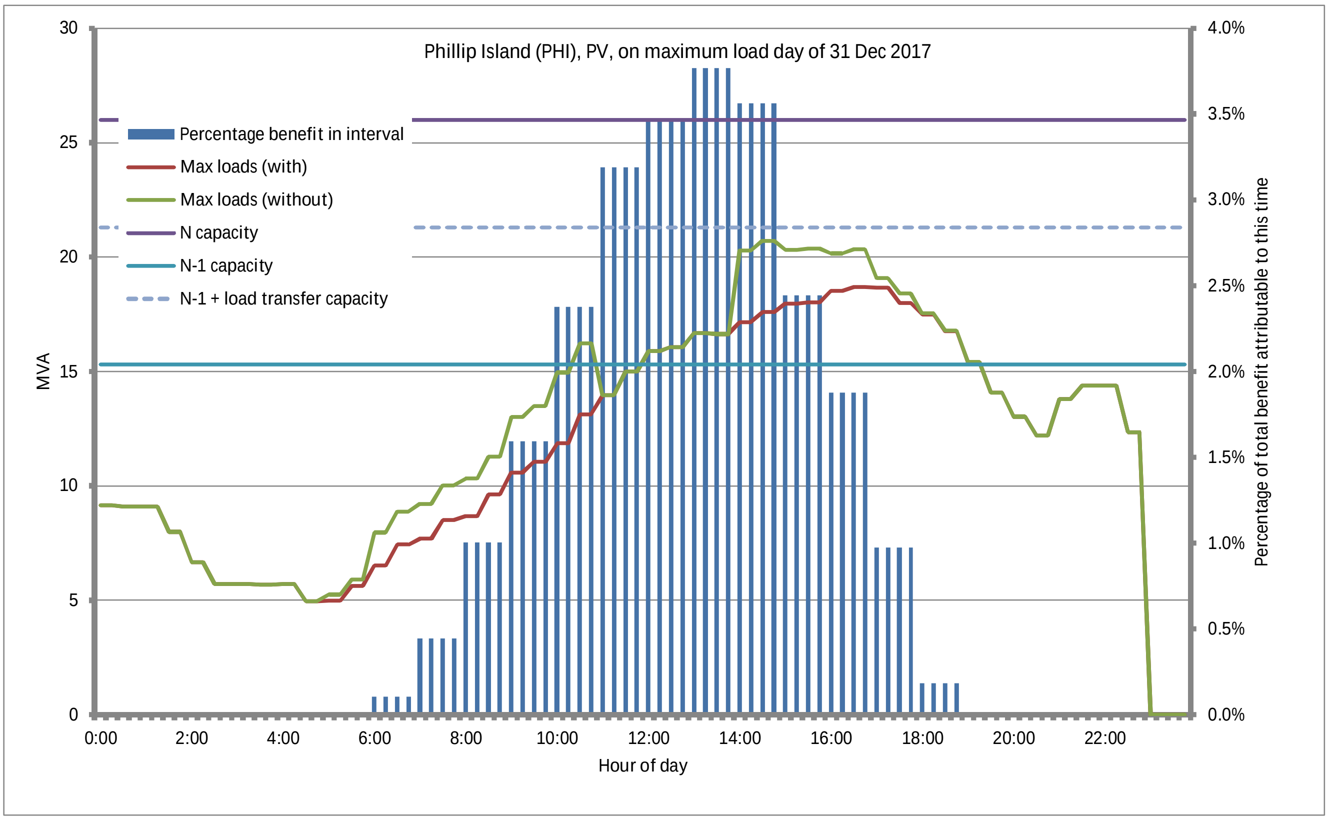


Figure 29 Proportion of value by hour, Werribee dispatchable DG



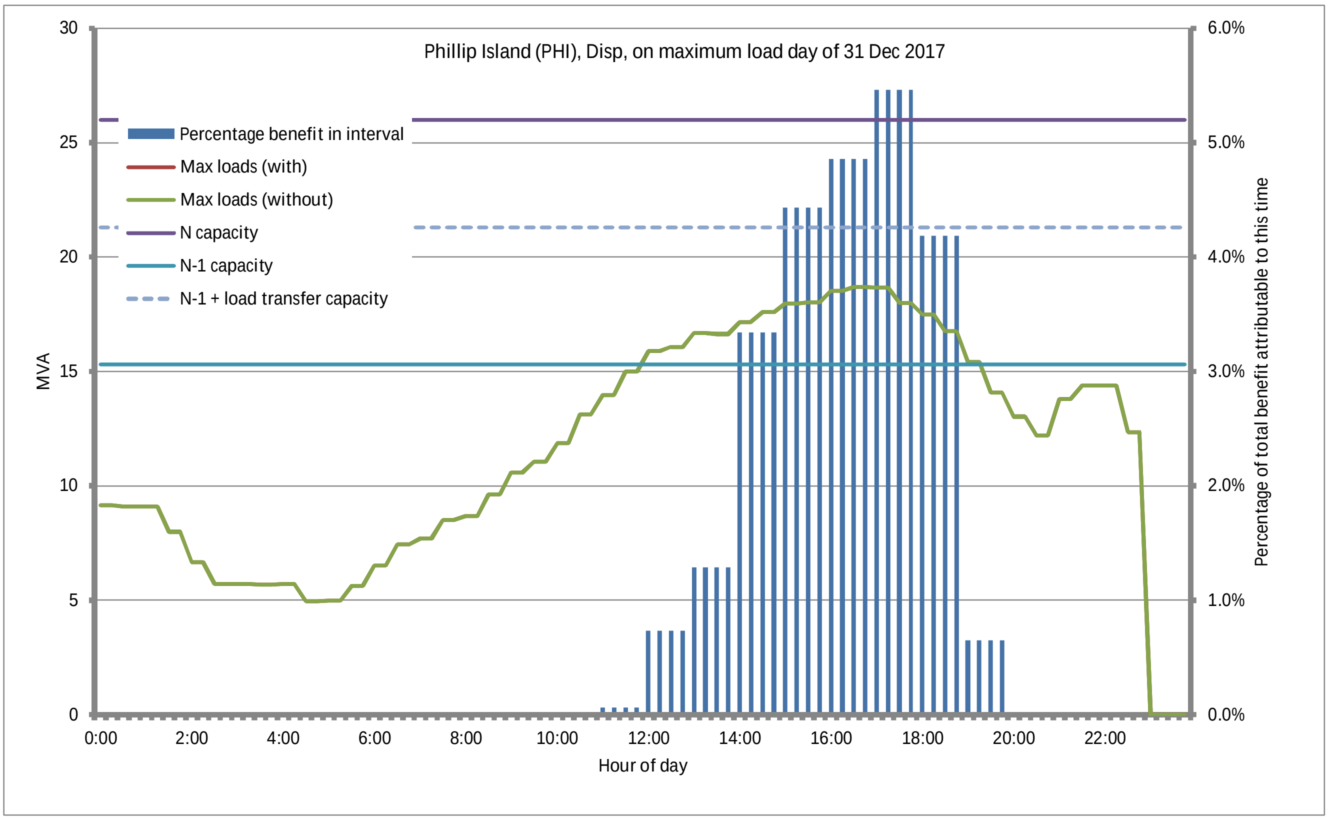
The Phillip Island location has a second peak-load during the day as shown in Figure 30. The maximum load is noted as being on 31 December at this location and this is likely to be caused by New Year's Eve celebrations. PV provides its maximum benefit in the early afternoon. As shown in Figure 30 there is a period around noon when the PV contribution apparently drops to zero on the maximum day. The PV is still shown as providing value because benefits are produced at the sub-transmission level which comes from Wonthaggi ZSS.

Figure 30 Proportion of value by hour, PV, Phillip Island 2017



There is no existing dispatchable DG listed for the PHI ZSS location however some benefit is still provided at this location due to benefits being indicated at the terminal station (MWTS) which is shared between nine zone substations with approximately 9 MW of dispatchable DG indicated across some of these. The calculated value across the day is indicated in Figure 31. The timing of the benefit will be influenced by the load profile of all nine relevant ZSSs in this case.

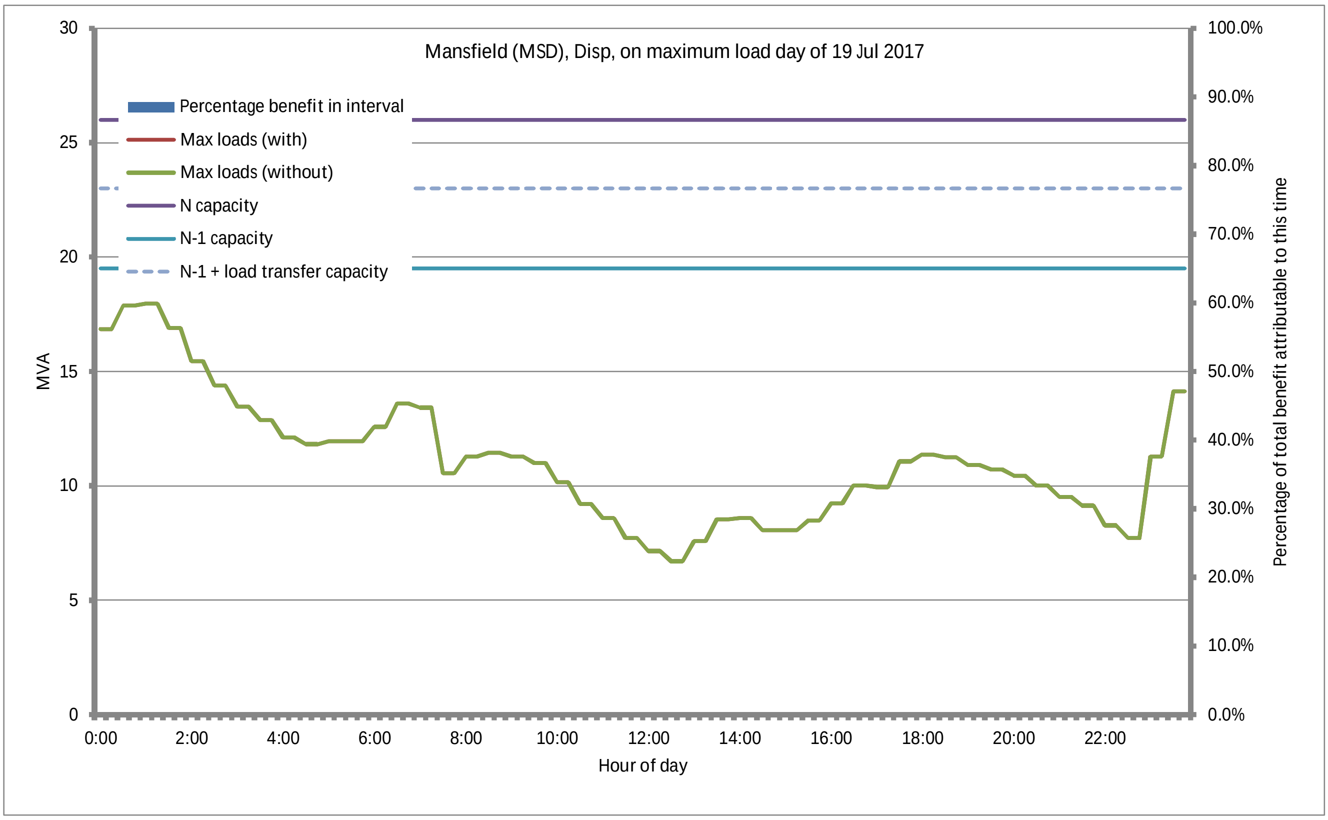
Figure 31 Proportion of value by hour, dispatchable DG, Phillip Island 2017



The Mansfield ZSS location load profile is shown in Figure 32. This location has its maximum load in winter which would potentially be a heating load. The peak at 1 am would be related to a hot water load.

There is no dispatchable generation at this location and only a small amount of PV, which does not contribute anything to the night time load. In any case the Mansfield location has sufficient substation capacity and would not indicate any benefit if some dispatchable generation existed.

Figure 32 Proportion of value by hour, PV DG, Mansfield 2017



At Mansfield, like many ZSS locations particularly in the east of the State a significant time-switched hot water load occurring around midnight can have a significant impact on Terminal Station, ZSS and sub-transmission loadings which can be impacted by dispatchable generation if it is arranged to operate at those times.

4. Sensitivity analysis

4.1 Introduction

Four calculation sensitivities were undertaken to obtain a better understanding of how the results might change with different calculation assumptions. The four sensitivities chosen include:

- Use of a **10% probability of exceedance (PoE) forecast baseline** (ie a more conservative weather outcome and its impact on network load) as a threshold for implementing infrastructure upgrades, as opposed to using a *blended* 50% and 10% PoE forecast baseline (that is, 30% x 10% PoE baseline + 70% x 50% PoE baseline). The higher forecast baseline is effectively a higher trigger for new infrastructure that could delay upgrades.
- **VCR 10% higher** than under the base scenario; as with the previous sensitivity, a higher estimate of VCR is likely to bring forward infrastructure upgrades, potentially increasing estimates of avoided infrastructure benefit.
- Under a 1%p **higher WACC**, the cost of infrastructure is higher, potentially increasing estimates of avoided infrastructure benefit.
- **No operating expenditure** benefit is included. Under this assumption, it is likely that benefits overall will fall, and again, it is useful to understand how much it will fall.

4.2 PV benefits

Table 7 which demonstrates the degree to which benefits of existing PV change with respect to the change to each calculation approach described. Of each of the calculation scenarios, the 10%-PoE calculation scenario demonstrates the greatest increase; this is because the amount of unserved load is highly sensitive to the demand at many substations. The High VCR and High WACC scenarios also show increased benefits of DG, implying that increases to the cost of infrastructure or the value of customer reliability will also increase the benefit of DG. Not including operating expenditure in the benefit list leads to reduction of benefit of around 7%.

Table 7 Relative change to base benefit estimates under each sensitivity

Sensitivity	Overall change compared to base calculation benefit		
	$000s	$/kW	%
10% PoE	886	0.81	29%
High VCR (+10%)	162	0.15	5%
High WACC (+1%p)	129	0.12	4%
No opex benefit	-197	-0.18	-7%

Figure 33 and Figure 34 provide greater level of detail on the above results, and demonstrate the change in benefit by asset class.

The asset class that seems to influence the overall results most strongly is the terminal substations. Under the 10%-PoE scenario in particular, the higher demand used in the calculations can strongly influence the level of benefit. This is also true for the sub-transmission assets, albeit to a lesser extent. These results imply that PV generation will delay in infrastructure more strongly under a higher (more conservative) demand scenario.

The results are not highly sensitive to the assumptions on VCR levels, the WACC and the opex allowance. The WACC and opex allowances are only relevant where the DG defers augmentations in the relevant year.

Figure 33 Comparison of PV benefits by calculation scenario

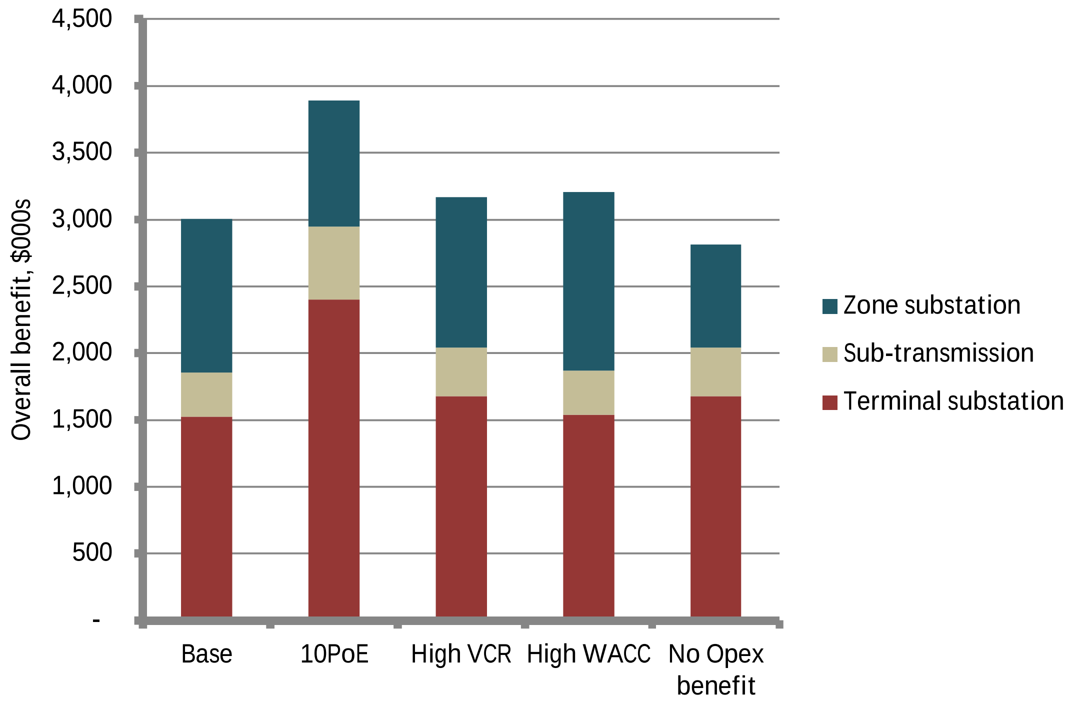
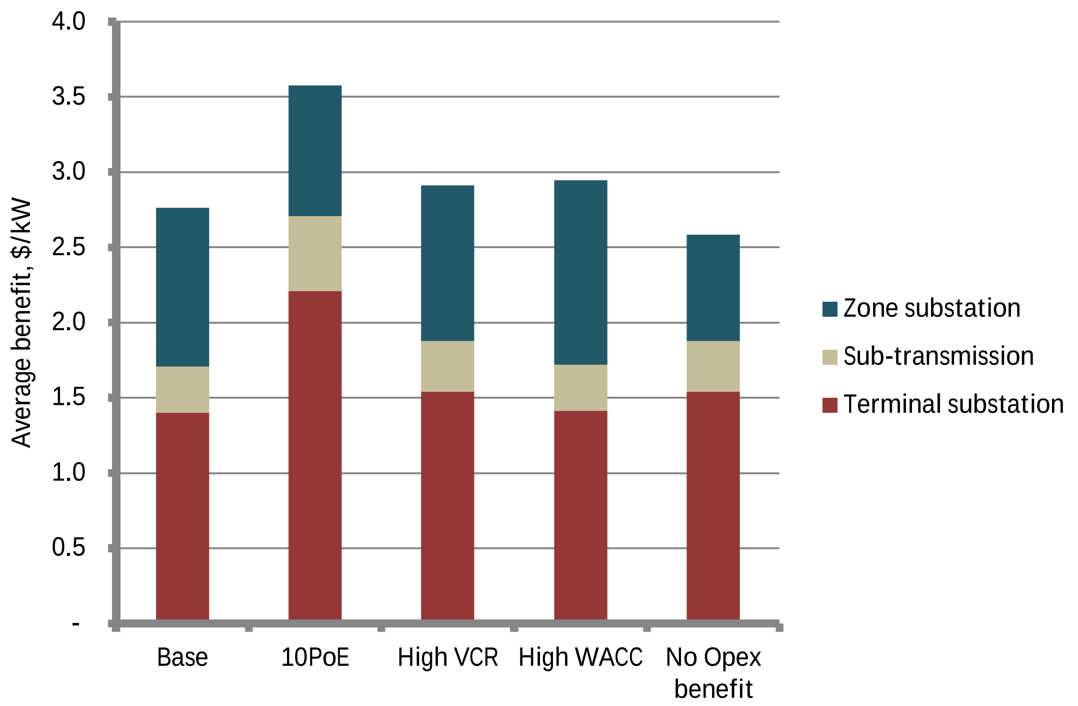


Figure 34 Comparison of average benefits by calculation scenario



4.3 Dispatchable system benefits

Dispatchable system sensitivities are summarised in Table 8. These are shown for the existing dispatchable DG. As with the case of PV, the 10 PoE calculation scenario yields a large difference in potential benefit, approximately 92% higher than the base calculation scenario, although the difference is significantly larger than for the PV case reflecting that dispatchable generation has a more direct effect on network benefits and the 10% PoE case reflects a higher load assumption and hence more energy at risk and avoided augmentations. Minor increases are evident in the high VCR and high WACC scenarios, and a moderate drop is evident with the No-opex benefit scenario.

Table 8 Relative change to base potential benefit estimates under each sensitivity

Sensitivity	Overall change compared to base calculation benefit		
	$000s	$/kW	%
10 PoE	561	4.74	92%
High VCR	12	0.10	2%
High WACC	66	0.53	11%
No opex benefit	-137	-1.10	-22%

Figure 35 and Figure 36 demonstrate the change in benefit by asset class.

The chart shows that sub-transmission benefits are negligible in all calculation scenarios. The terminal substations however show significant deviations under the alternative calculation methods in the 10% PoE scenario as was found for the PV DG case.

The zone substation benefits are more impacted by the High WACC and no-opex scenarios each of which reflect augmentation avoidance rather than energy-at-risk avoidance benefits.

Figure 35 Comparison of overall benefits by calculation scenario

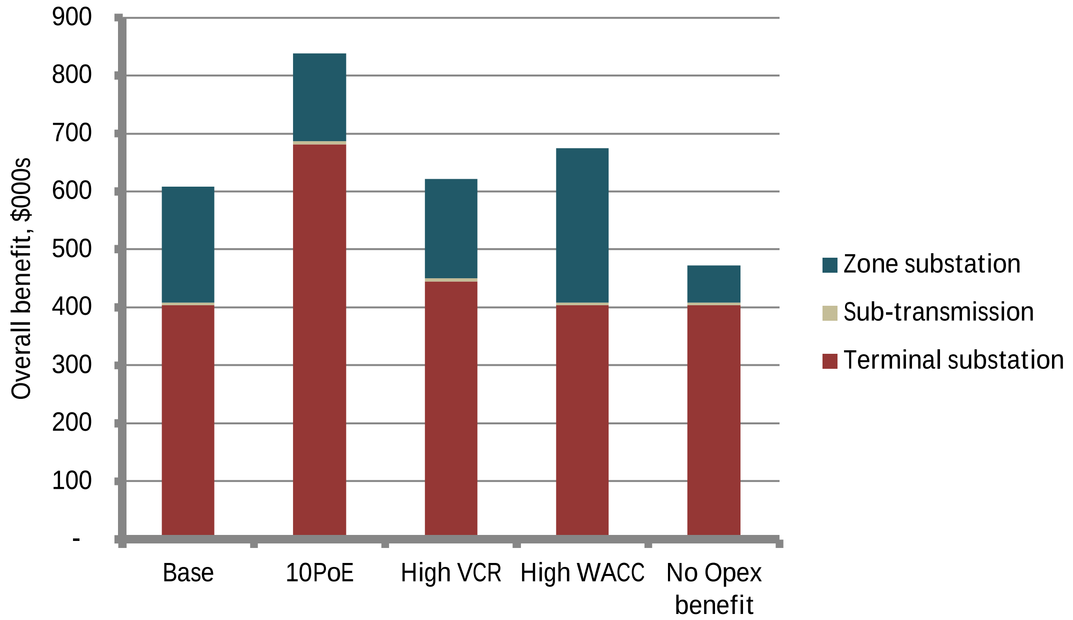
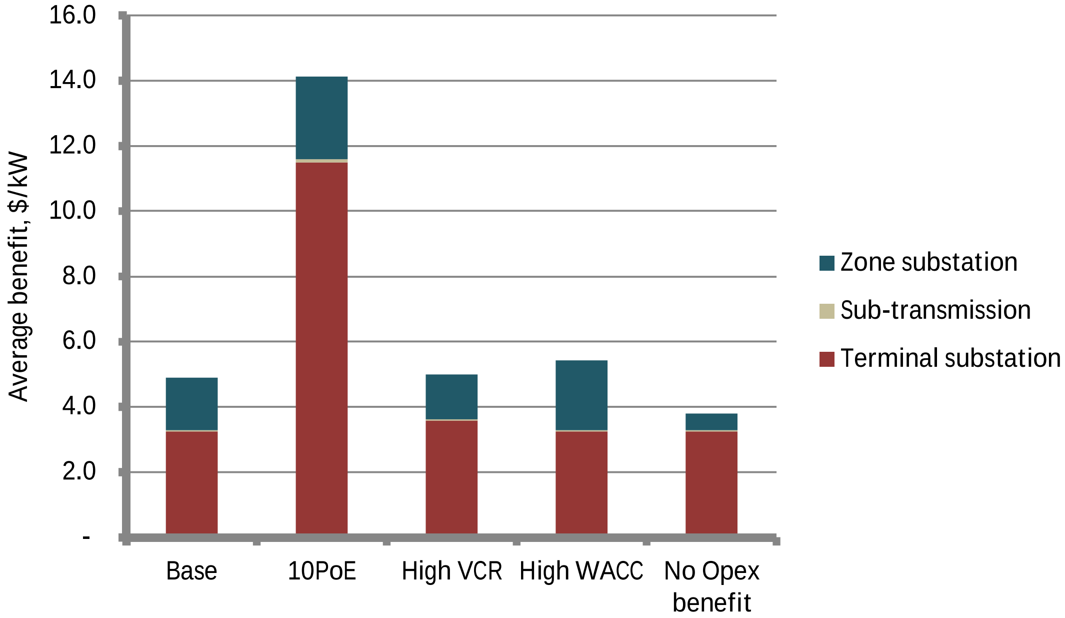


Figure 36 Comparison of average benefits by calculation scenario



4.4 Combined DG system benefits

Combined existing DG system sensitivities are summarised in Table 9.

The combined potential benefits change most under the 10PoE scenario, with $1.6 million or $1.4/kW additional benefit available if a higher trigger point was used for new infrastructure, an approximate increase of 45% above the baseline calculation method. A review of Figure 37 and Figure 38 shows that most of this is due to change in benefit at the terminal substation system level, with relatively minor change shown elsewhere.

Table 9 Relative change to base potential benefit estimates under each sensitivity

Sensitivity	Overall change compared to base calculation benefit		
	$000s	$/kW	%
10 PoE	1,641	1.39	45%
High VCR	238	0.19	6%
High WACC	219	0.18	6%
No opex benefit	-382	-0.31	-10%

Figure 37 Comparison of overall benefits by calculation scenario

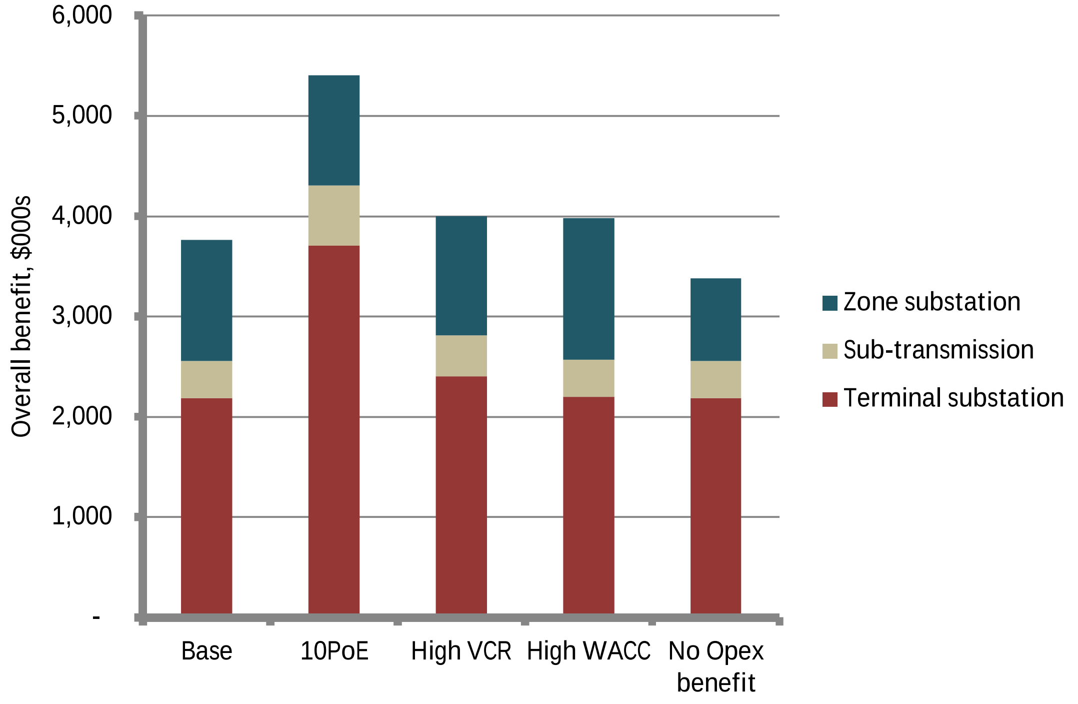
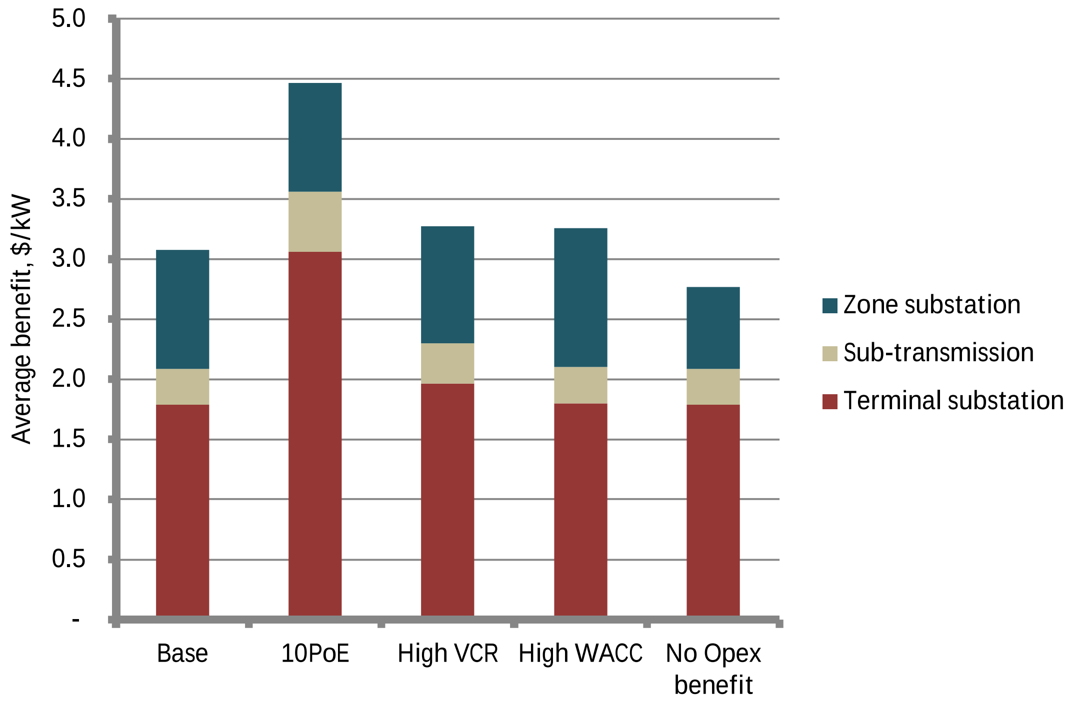


Figure 38 Comparison of average benefits by calculation scenario



The sensitivities are consistent with those of the PV and dispatchable DG sensitivity cases in Sections 4.2 and 4.3 respectively.

5. Discussion – value of reducing network congestion

5.1 Introduction

Based on the numerical outputs from Jacobs' calculations described in Sections 3 and 4, the following conclusions have been drawn:

- Distributed generation can and does provide network value in Victoria:
  - By reducing peak demand, it provides the benefit of "reducing network congestion"
  - The benefit of reducing network congestion can be valued by calculating the deferred capital investment and the value of improving network reliability.
- Existing solar PV (the majority of installed distributed generation in Victoria) is creating value of:
  - $10 to 40 per kW at 6 zone substations
  - $5-10 per kW at 22 zone substations
  - <$1 per kW at the majority of zone substations in Victoria
- Existing dispatchable distributed generation in Victoria could potentially be creating value of:
  - $10 to $60 per kW at 25 zone substations
  - $1 to $10 per kW at 38 zone substations
  - <$1 per kW at the majority of zone substations in Victoria

Because there is substantially more existing PV DG in Victoria (1088 MW est. in 2017) than dispatchable forms of DG (est. 124 MW in 2017), the existing PV contributes much more benefit in dollars per year terms ($3,006k/year versus $609k/year in 2017).

The value of an increment of DG capacity over-and-above the quantities that exist or are built-into the distributors' load projections also varies, with an increment of PV having a benefit greater than $10/kW at three zone substations with benefit up to $26/kW and an increment of dispatchable DG having a potential benefit greater than $10/kW at 35 zone substations with benefit up to $178/kW.

Additional observations may also be made as follows.

5.2 Locational dependence of benefit

As noted in Sections 3.2.3 and 3.3.3, the benefit provided is highly locational varying significantly from place-to-place.

Where the benefit is dominated by benefits produced at a terminal station, then the locations identified by the zone substations connected to that terminal station may each have high benefit – for example Sunshine East, Sydenham, Pascoe Vale, Sunbury, Gisborne, Tullamarine, Braybrook, Woodend, Airport West, Essendon and Melton are identified in Figure 10 as having substantially the same benefit. These zone substations are all fed from the Keilor Terminal Station (KTS) which produces most of the (existing PV) benefit for these locations.

Where the benefit is provided at the zone substation or subtransmission feeder level then the benefits can be far more locationally variable. For example Thomastown zone substation (TT) is indicated as having a high benefit from existing PV of $18/kW whereas the next nearest zone sub-station of Epping (EPG) only 4.6 km away is indicated as having a benefit of only $0.2/kW.

Variations in benefit over short distances can arise because of the different circumstances at individual zone substations. With the existing level of PV at Thomastown (7 MW in 2017) there are no augmentations planned in the next five years however energy at risk under an N-1 condition commences to rise from 2016 onwards. If the existing PV were removed then the level of energy at risk would rise. The existing PV provides benefit in reducing this energy at risk. Thomastown would be augmented in 2018 if the PV did not exist. Epping on the other hand has no requirement for upgrade regardless of the existing PV DG.

That two zone substations can have different circumstances despite being nearby can arise because one substation may have been upgraded recently and the other not. The upgraded substation will have no requirement for further upgrade for a long time given that an upgrade with a new transformer can add a large portion of capacity[19].

Given that upgrades have occurred to substations as they have historically required them, under different locational circumstances, zone substations can be at different phases of the upgrade cycle and hence the benefits calculated can differ from location to location in a somewhat random fashion.

5.3 Time dependence of benefit

As noted in Figure 12 and Figure 19 in Sections 3.2 and 3.3 respectively, the benefit can vary with time, by year, over the calculation period to 2020. For some locations the benefit rises (eg Barnawatha) and at others the benefit may fall (eg Sunbury) over the period.

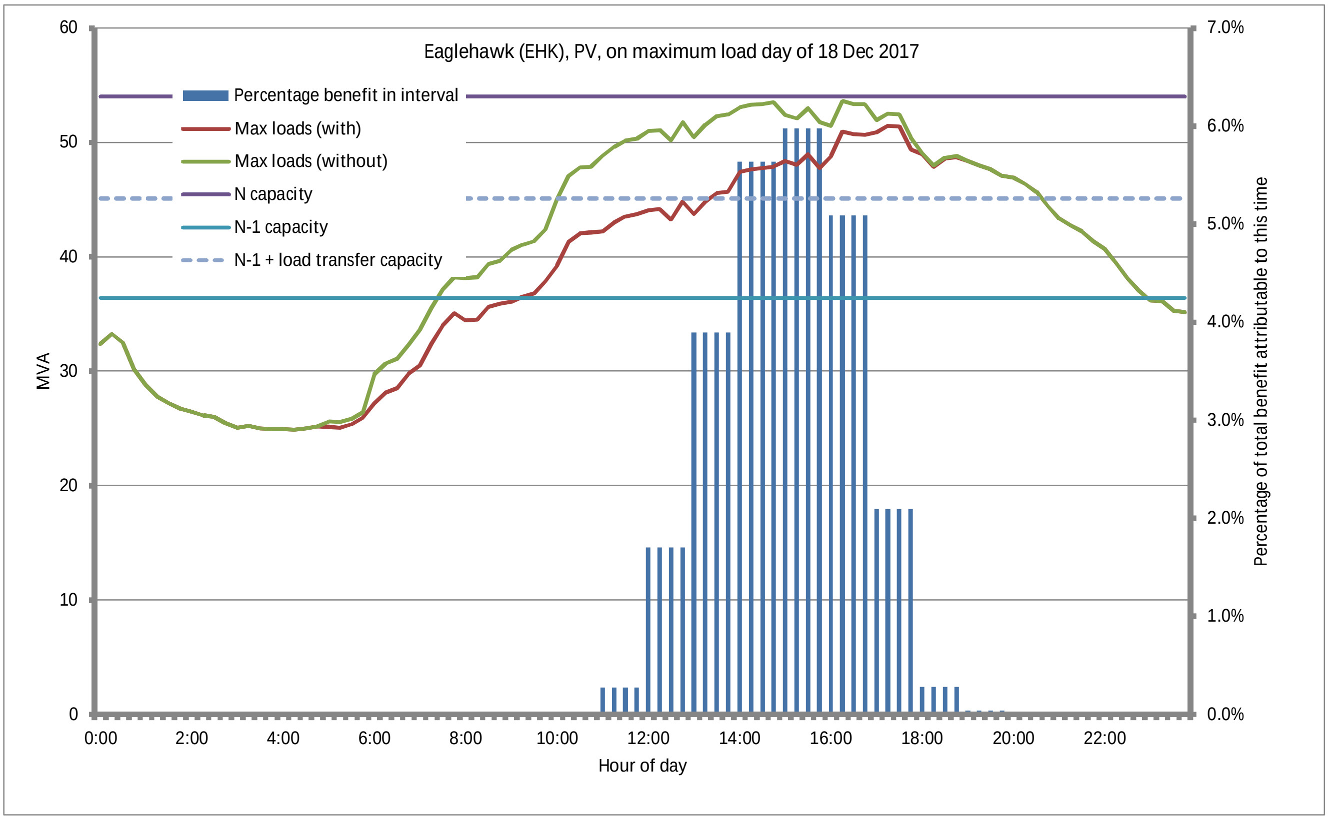
Where there is no augmentation anticipated, and with load growth, the amount of energy at risk will progressively rise. This can be diminished by the presence of DG and hence the calculated benefit will rise. At some point the amount of energy at risk will rise to the point where an augmentation would be warranted with or without the DG. At that time the calculated benefit will drop.

As noted in Section 5.2, different locations can be at different phases of their upgrade cycle at any time and hence some locations will have benefits that rise and some will fall, in a somewhat random fashion.

As noted in Section 3.7 the benefit is also time-dependent within the day. At most locations the maximum load occurs in the late afternoon. Eaglehawk ZSS has such a load profile (Figure 39) with a maximum load between 3pm and 6pm in summer.

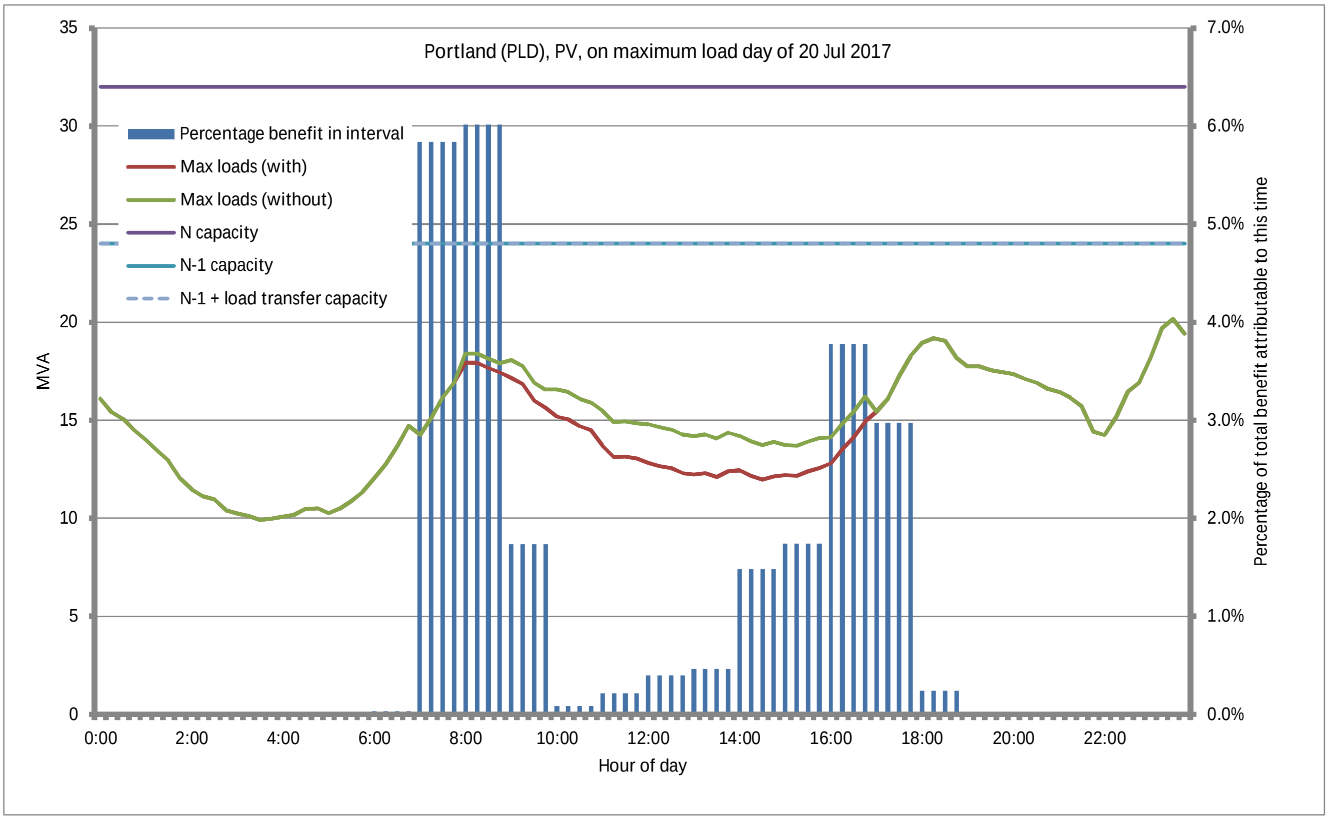
[19] A substation with only a single transformer will typically achieve 100% extra capacity with an additional transformer. A two-transformer substation will typically achieve 50% extra capacity with the addition of another transformer.

Figure 39 Daily profile and calculated hourly benefit for Eaglehawk ZSS



At other ZSSs, the load could peak in winter such as at the Portland location (Figure 40). For this location three distinct peaks are evident within the day – a morning peak, a late afternoon peak, and a third peak just before midnight attributable to time-switched hot-water loads. For such sites the benefits provided by PV will be greatly reduced or eliminated. The benefit provided by existing PV at Portland is relatively low at $1/kW and this benefit is wholly derived at the terminal station level. A dispatchable form of DG has significantly greater benefits than PV for such a site – the benefit provided by existing dispatchable generation at Portland is calculated as $57/kW.

Figure 40 Daily profile and calculated hourly benefit for Portland ZSS



5.4 Comparison of calculated transmission level benefits to Avoided TUOS

5.4.1 Introduction

Avoided TUOS refers to a benefit accessible by (generally larger) embedded generators within distribution networks under the NER Chapter 5 Clause 5.5 (h) and (i) - *avoided charges for the locational component of prescribed TUOS services*.

The Avoided TUOS calculation is a different method to the economic counter-factual calculation applied in this review under Section 2.4.3. The Avoided TUOS method calculates the share of (locational) transmission costs that are attributable to the export of DG into the local distribution network as opposed to the electricity having come from the transmission network. In the short-term, a portion of transmission network charges reflecting lower electrical demand at the transmission terminal station due to the embedded generator are passed to the embedded generator and the costs are re-distributed to other customers in the distributor's network. In the long-term, after transmission augmentation capex has been avoided, transmission charges to customers in the relevant distribution network area will be lower than they would have otherwise been.

The Avoided TUOS calculation is undertaken for comparison with the value calculated under the counter-factual method for the transmission component of economic benefits.

5.4.2 Method

For the Avoided TUOS calculation the calculation is made following the method applied for larger embedded generators under the NER. This is a "with" versus "without" calculation based on the generator's output in a year. This is calculated on an ex-post annual basis under the NER.

The calculation applies the published tariffs at the relevant terminal station rather than any calculation of VCR or augmentation costs.

The method applied is:

- Calculate when the 10 days of max system demand at the stated time bands occurred in 2015
- Calculate the average 30min maximum demand at the relevant terminal station (eg Redcliffs) on those 10 days, with and without the distributed generation estimated exported[20] electricity
- Apply the 2015/16 TUOS tariffs to calculate the TUOS quantity based on the locational tariffs. The non-locational and general tariff components are not used in this method.
- Note that the marginal amount of benefit will be the same as the total amount of benefit under this method

Only generation on the relevant 10 days in the year will produce a benefit under this method.

For the purposes of determining locational TUOS charges avoided, the exported electricity is required rather than the generated electricity. For this purpose the data obtained by ESC for net outputs of a sample PV systems in Victoria has been utilised.

5.4.3 Results

The results of the Avoided TUOS calculations at terminal station level are shown in Table 10. For comparison the results from the counterfactual model for the transmission part of the network are also shown.

Table 10 Results of the Avoided TUOS calculation compared with the counter-factual model

TSS	Locational Price (Exc GST) ($/MVA)	Change in peak (MVA)	Avoided TUOS ($000)	MW PV 2017	$/MW avoided TUOS	Counter-factual model - transmission component $/MW
ATS West	17102	1.55	26.51	57.7	459.3	1,688.6
ATS/BLTS	17102	0.18	3.14	11.3	278.8	0.0
BATS	23112	1.00	23.04	36.6	630.0	10.7
BETS	28452	1.01	28.75	41.5	693.2	279.5
BLTS	17833	0.58	10.41	8.7	1,199.6	0.0
BTS	12540	0.18	2.31	7.0	331.9	0.0
CBTS	11867	1.57	18.60	85.4	217.7	0.0
ERTS	12089	2.61	31.57	43.6	724.3	0.0
FBTS	16162	0.29	4.63	3.1	1,483.0	0.0
GNTS	16813	0.10	1.63	16.0	101.3	0.0
GTS	19121	5.46	104.42	77.7	1,344.2	0.0
HOTS	37920	0.39	14.76	17.6	839.7	0.0
HTS	15177	0.59	9.00	22.3	402.7	0.0
KGTS	38031	0.48	18.13	10.2	1,771.8	0.0
KTS	16280	4.40	71.67	63.6	1,127.8	9,481.9
MBTS	4358	0.29	1.27	12.9	98.2	0.0

[20] The without case is "*if that Embedded Generator had not injected any energy at its connection point during that financial year*"

TSS	Locational Price (Exc GST) ($/MVA)	Change in peak (MVA)	Avoided TUOS ($000)	MW PV 2017	$/MW avoided TUOS	Counter-factual model - transmission component $/MW
MTS	17402	0.15	2.60	15.7	165.5	0.0
MWTS	5507	2.25	12.39	94.9	130.5	859.3
RCTS	48343	1.32	63.84	15.6	4,101.1	598.9
RTS	13873	0.92	12.80	14.4	890.9	1,642.6
RWTS	13071	1.73	22.58	67.4	335.0	0.0
SHTS	21628	2.69	58.24	58.4	997.6	0.0
SMTS	13130	0.35	4.58	46.2	99.2	229.5
SVTS	12143	1.04	12.62	32.4	389.2	0.0
TBTS	15947	0.25	3.93	42.0	93.6	0.0
TGTS	34850	0.23	7.84	23.8	330.1	1,047.8
TSTS	14300	0.19	2.65	29.3	90.3	0.0
TTS	13403	4.53	60.69	29.4	2,062.0	0.0
WETS	49607	0.17	8.34	1.9	4,359.0	0.0
WMTS	15576	1.83	28.48	13.3	2,141.4	0.0
WOTS	9685	1.82	17.66	15.9	1,108.6	13,624.4
Total		**40.1**	**$689**	**1015**		

The total Avoided TUOS is shown as $689k across the State compared to the transmission benefit value calculated from the counterfactual model of $1,524k/y.

The avoided TUOS calculation comes to a lower estimate than the counterfactual model of transmission level benefits per year, and the distribution amongst terminal stations of the value is very different. This is to be expected as:

- Avoided TUOS applies only to the export component of generation. This is a very different value than the total PV output and capacity. The export component is dictated by the size of the PV facility relative to the customer’s load. Customers who have the benefit of the (former) enhanced $600/MWh feed-in-tariff had an incentive to oversize the PV facility relative to their own load and to export more electricity. The enhanced incentive to export has been removed from later feed-in tariffs and consequently there would be expected to be reduced exports from more recent residential PV systems as they may be more matched to household consumption.
- TUOS charges are based on distributing historical costs attached to the terminal station, rather than the incremental avoided costs (with/without)

6. Results and discussion – other potential network benefits

6.1 Introduction

As noted in Table 2 in Section 1.4 several areas of potential benefit believed to be immaterial were tested by indicative calculations to confirm that any benefit is likely to be immaterial. These areas are:

- Network support benefit (the avoided cost of generation from network support facilities; e.g. backup diesel generation)
- Voltage regulation (the reduced cost of maintaining voltage levels)
- Maintaining power quality benefit (including the management of harmonics, DC injection and flicker)
- Additional congestion reduction benefit (the avoided costs associated with congestion applied to energy sourced from constrained networks),
- Islanding benefits (the ability to create a stable island network during a fault).

6.2 Network support benefit

At some locations in the network DNSPs have found that non-network alternatives to a network upgrade is the lowest cost option and have entered into Network Support Agreements with generation suppliers to provide the service. Typically these plants are natural gas or distillate fuelled engines or gas turbines. Examples include the Bairnsdale generation project (2 x 40MW gas turbines) in AusNet's system.

The cost of running the plants has already been incorporated into the network service agreement tariff and the total cost has been found, by definition, to have been less than the annualised cost of the network alternative.

DG at the same location could obviate the need to run these plants and hence save some fuel consumption. The Bairnsdale plant operates regularly and in particular provides support for the switched hot water load at circa midnight.

This is a highly localised requirement and Bairnsdale is the only known extant example.

In the future the Bairnsdale service could conceivably be provided by a large battery project (or a series of coordinated small battery projects) however this is not likely in the forecast timeframe to 2020.

In the more common case where the DG is backing up an N-1 contingency event the probabilistic annual operation would be of the order of 0.5% of hours. These services are only deployed on a small percentage of ZSSs and backing up typically a 20-40 MVA transformer failure contingency. Thus the total fuel used is likely to be less than 100TJ.

However this potential benefit of this saved fuel is already included within the value ascribed to VCR benefits in the analysis since the fuel, opex and capex used in the plant would have been compared to, and been shown to be less than, the cost of the network augex alternative project for the non-network option to have been selected. Accordingly no additional benefit should be recognised.

6.3 Voltage regulation

Voltage control projects are sometimes considered where high impedance network elements exist and under high load conditions, or where load or reactive power requirements rise relative to original design specifications.

In the forecast time horizon, Jemena's DAPR describes projects including 8 MVAr capacitor banks at four ZSSs and voltage regulators on two feeders. Voltage regulators are not expensive in a relative sense being typically in the order of $250,000. 8 MVAr capacitor banks cost approximately $2.2 million. AusNet describe two 6 MVA capacitor banks at two ZSSs. These are typical and reflect a small number of ZSSs having voltage regulation issues at any time. Some of this requirement is itself due to the proliferation of small scale PV with simple inverters.

Particular forms of DG, such as those with synchronous generators (eg cogeneration plants) can provide or consume reactive power. Generation into the network can also assist voltage support at highly loaded locations. A typical 1 MW cogeneration plant with a generator capable of 0.8 power factor could only provide 0.75 MVAr and hence could only provide a portion of the need identified above at a typical substation.

The annualised cost of deferring or avoiding capex on voltage regulation across the system is likely to be less than $500,000/year, of which only a small portion could be deferred or avoided by practical DG plants of the scale relevant to this review. Only particular forms of DG can provide this service and the need for the service is relatively sparse in the network. Jacobs considers this potential benefit to be immaterial.

DNSPs when considering non-network alternatives to a voltage regulation project could consider DG where the need arises.

6.4 Maintaining power quality benefit

These are controlled by controlling the characteristics of connected equipment rather than by a service provided by generators. DG (like other connected equipment) should be designed to not produce any of these undesirable characteristics such as harmonics, DC injection and flicker, rather than actively reducing the impacts of other system users.

6.5 Additional congestion reduction benefit

Congestion benefits in the network at terminal station level and below will equal the network capacity benefit calculated within the analysis. At transmission level outside of the terminal stations some additional benefit might arise from the impacts of the DG beyond the relevant terminal station that is included in the analysis.

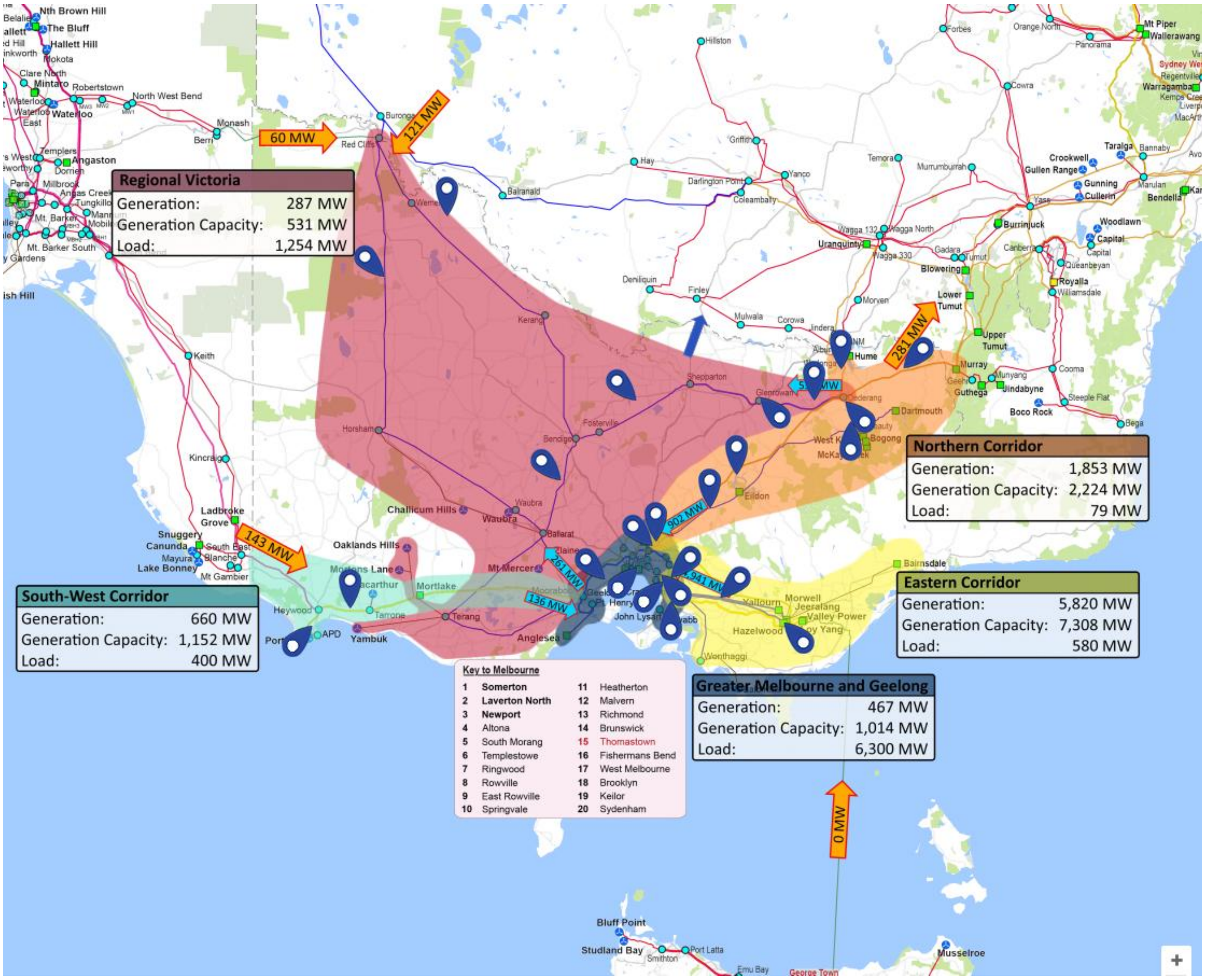
Figure 41 shows AEMO's high-demand "snapshot" for Victoria by region and potential limitations that are being monitored by AEMO. Only within the "Regional Victoria" and "Greater Melbourne and Geelong" regions are the monitored limitations of a type that are potentially benefitted by additional DG. The other regions already have effectively high values of generation relative to load.

Of the regional Victorian limitations only a subset are believed to be potentially relevant (associated with local demand growth or insufficient reactive power support). The remainder are considered more associated with increased generation (predominantly wind and some large-scale solar projects) in this area of the State and hence could be adversely affected by new DG.

In Greater Melbourne/Geelong, the limitations noted could be reduced by increased DG as they would be triggered by increased demand. Some that are related to export capability to NSW would not be benefitted by DG.

AEMO is monitoring the limitations based on the net load on the transmission system and hence the presence of existing and projected DG is already assumed within the values shown. Congestion in the Regional and Greater Melbourne/Geelong areas would thus be worse if the DG did not exist.

Figure 41 AEMO High Demand Snapshot and monitored limitations for Victoria[21]



The potential limitations noted are only being monitored at present and have not yet triggered an upgrade study (such as a RIT-T). AusNet Services (Transmission) capex model[22] for the period to 2022 does not include network any augmentation expenditure categories that could be offset or deferred by additional DG. AEMO's Victorian APR[23] has no augmentation capex expected for load growth in the next ten years. AEMO has no open RIT-T evaluations in Victoria at present. At presently anticipated load growths these limitations are likely to be outside the 10 year planning horizon for transmission.

AEMO previously undertook a RIT-T analysis of the Regional Victorian Thermal Capacity Upgrade proposal and in February 2015 installed wind monitoring equipment to allow an upgrade of the capacity of the Ballarat–Bendigo 220 kV line. AEMO have committed to the second stage of this project, installing a third Moorabool – Ballarat 220 kV circuit in 2017–18. AEMO are proposing a Stage 3 project to re-conductor the Ballarat – Bendigo 220 kV line in about 2018-19 but this has been put on-hold. The approximate load-at-risk that these upgrades were addressing was 250-300 MW. This load-at-risk arose under N-1 outage scenarios.

AEMO are expected to issue a RIT-T in 2016 for congestion in the Ballarat/Horsham corridor however this is stimulated by additional wind farm connections and not by load.

[21] Produced using AEMO's Interactive Map (http://52.63.206.133/aemo/apps/nem_map/index.php) accessed 20 Oct 2016
[22] AusNet Services - AST Transmission 2017-22 TRR - Capex Model - October 2015
[23] AEMO "Victorian Annual Planning Report", June 2016

Considering the Regional Victorian Terminal Stations, these have approximately 150 MW of DG connected. The high demand point noted was on 23 February 2016 at 15:30. Temperatures were approximately 40^{o}C in Bendigo. Approximately 50% of PV capacity would be expected to be produced, or around 75 MW, or 6% of the Regional Victorian Load.

Given that the Stage 1 and 2 of the RIT-T have proceeded, and future limitations are believed to be more driven by additional generation, the benefit provided by DG in the < 5 MW size range is not expected to be material with respect to future capex deferral in the forecasting period.

Diversity of generation (location and technology) could reduce the risk of a full system failure however the annual probability of a full system failure is extremely small and hence the value is considered immaterial.

6.6 Islanding benefit

The main benefit of an islanding capability is captured by the project proponent in being able to continue using electricity when other customers are interrupted.

Back-up diesel generation at the facility level is generally the most favoured technology for those customers that need a higher reliability of supply than average. The quantity of back-up generation in Victoria is unknown as it does not generally have to be reported. The private (internal) benefit provided to the owner by back-up generation is excluded from the calculations in this review. There may be second order impacts through the benefits to the broader economy of not losing a portion of the economic multiplier effect of grid outages (eg benefit to suppliers and customers of the facility).

New installations of DG that have islanding capability, including batteries at facilities and/or mini/micro grid arrangements, could provide similar benefits to the broader economy. Different sectors would have different multiplier effects, for example industrial facilities with islanding capability would have a relatively high multiplier benefit and residential areas with islanding facilities would have low multiplier benefit to the broader economy.

Appendix A. Worked example – existing PV at Werribee ZSS

A.1 Introduction

A calculation of the benefits provided in 2017 by existing PV at Werribee ZSS is provided to illustrate the method applied in the counterfactual calculation. The example calculation is for the ZSS level benefits.

Werribee (WBE) ZSS is in Powercor's distribution area.

A.2 Parameters

Table 11 Parameters for WBE

Parameter	Value
N Capacity (Summer) (MVA)	99
N Capacity (Winter) (MVA)	99
N-1 Capacity (Summer) (MVA)	82.8
N-1 Capacity (Winter) (MVA)	92.2
Load Transfer Capability (Summer) (MVA)	16.7
Load Transfer Capability (Winter) (MVA)	33.7
Embedded Generation -Dispatchable (MVA)	1.8
Embedded Generation -Wind (MVA)	0
Solar Capacity at substation (MW)	18.3
DLF	1.0698[24]
Augment 1 Size (MVA)	4.4
Augment 2 Size (MVA)	33
Augment 1 Capital cost ($M)	1.59
Augment 2 Capital cost ($M)	4.5
Augment 1 Life (years)	75
Augment 2 Life (years)	51
Load Data Resolution	15min
Load Data Basis	Calendar Year
VCR ($/MWh)	34,900
WACC (nominal vanilla)	6.11%
No. of transformers	3
TSS Supply	ATS West
Peak Season	Summer
PF at peak	0.99

[24] From AEMO "Distribution Loss Factors 2015/16" 18/5/2016 using average of long and short sub-transmission values. At ZSS level $^{2}/_{3}$ of the loss factor (deviation from 1.000) is applied

Table 12 WBE Summer maximum demand (MVA)[25]

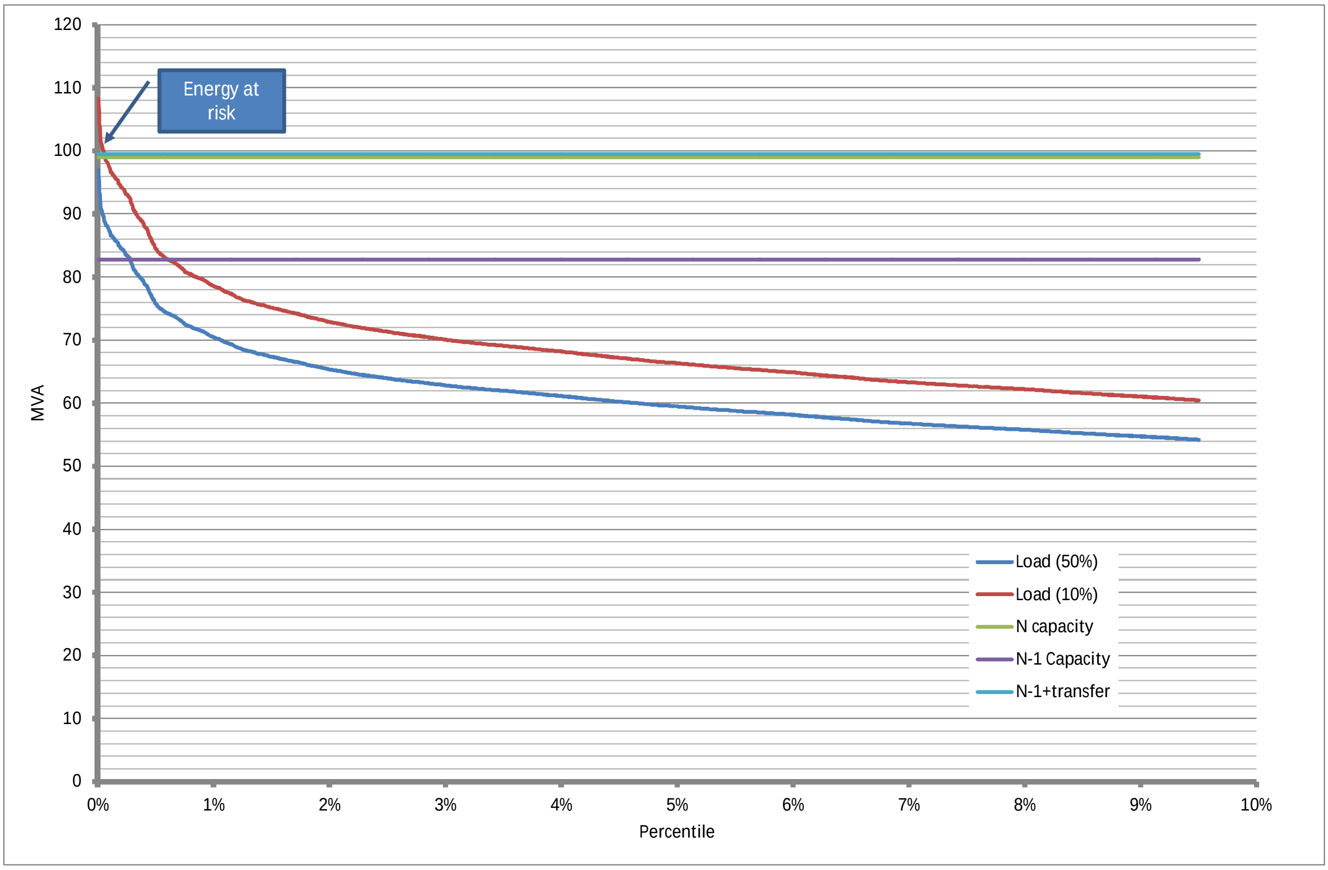
Percentile exceedance	2016	2017	2018	2019	2020
50%ile	94	97.1	101.1	105.2	109.6
10%ile	104.8	108.3	112.8	117.3	122.2

A.3 Analysis

The actual loads for WBE ZS for 2015 were extracted from the zone substation data published by Powercor. The maximum load at WBE in 2015 was 94.07 MVA which occurred at 5pm on 19 December. The loads from 2015 are scaled up to reflect the loads in 2017 by the ratio of the relevant load in Table 12 to the maximum actual load (94.07 MVA). When sorted from largest to smallest these values produce a load duration curve which can be compared with the substation capacities from Table 11. These are shown in Figure 42. Note that the N-1 capacity plus the summer load transfer capability is 99.5 MVA which is approximately equal to the N rating of 99 MVA for WBE. Consequently the two chart series are overlain on the chart.

The quantity of energy-at-risk is the area of the portion of the load duration curve that lies above the relevant capacity of the substation.

Figure 42 Projected load duration curve (top 10%) for WBE ZSS in 2017



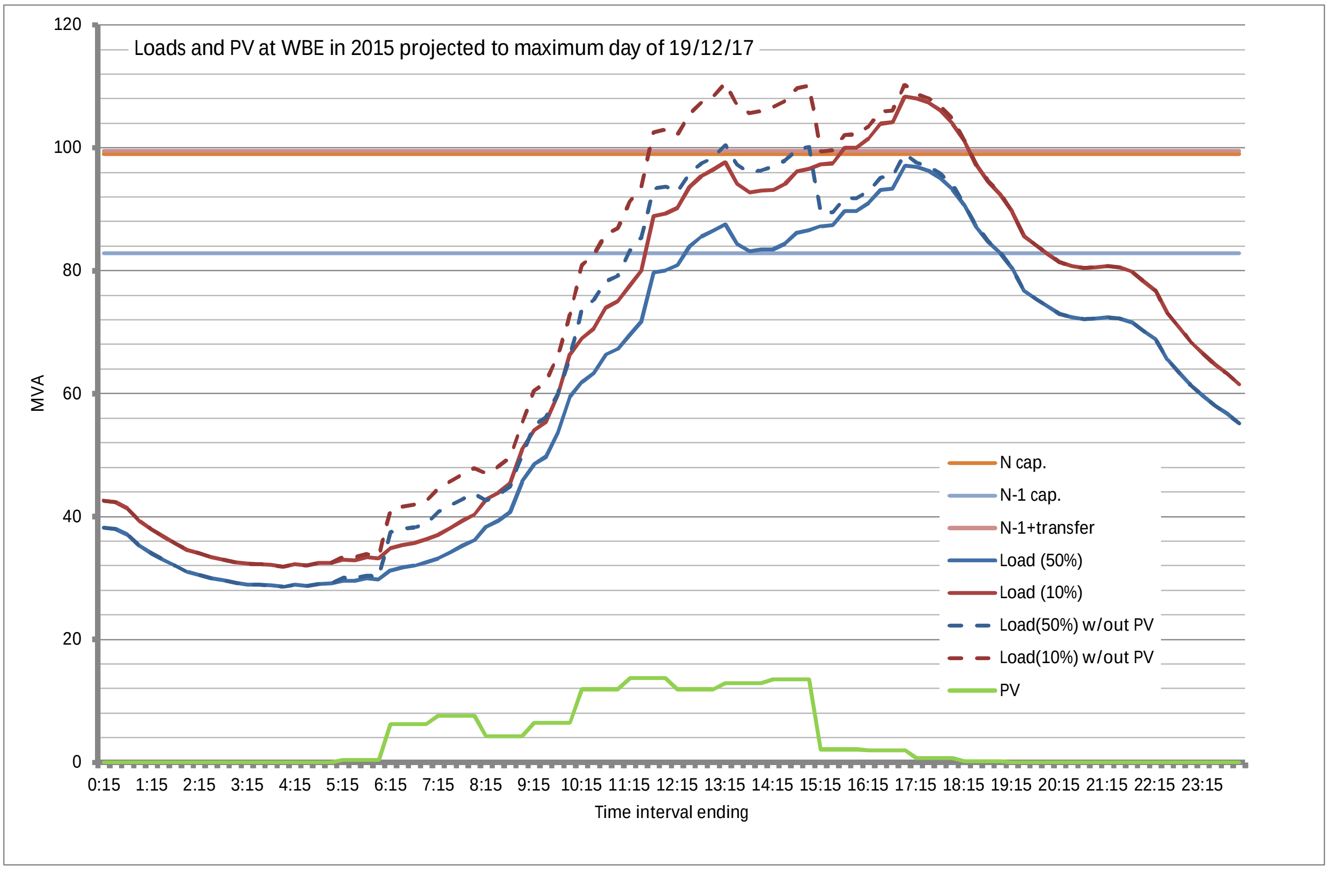
[25] 50%ile demands are taken from the Powercor "Distribution Annual Planning Report", December 2015 (rev2). 10%ile loads are estimated by considering the ratio between the 10%ile and 50%ile weather corrected maximum demands for WBE listed in the 2014 Category Analysis RIN response of Powercor submitted to the AER. The ratio is 1.115.

Using the Bureau of Meteorology insolation data for 2015 a theoretical quantity of solar PV in MW per MW of capacity is produced for each hour of the year. The projected capacity of PV at WBE in 2017 was estimated as 26.1 MVA taking the projected growth of solar PV in Victoria estimated by Jacobs for AEMO and apportioning this growth to the Victorian zone substations proportionate to the growth from 2015 to 2016 for postcodes near WBE in the Clean Energy Regulator's "Postcode data for small-scale installations".

Given that residential PV systems are in general oriented and sited with some sub-optimality relative to an ideal PV installation (oriented north and sloped at the latitude angle of the site, and unshaded), Jacobs have a determined a set of factors that can be applied to estimate the average output over the hours in a day of a number of small scale PV systems relative to optimally aligned and positioned systems. This was calculated by considering the actual outputs of a set of systems within a 50km radius in Sydney. The determined factors have been applied for each hour to reflect this adjustment. An hourly profile of representative PV generation for each hour of the year can thus be generated.

The load profile at WBE "with" the PV in-place is represented by the actual load at the substation. The load profile "without" the PV in place is represented by adding the estimated PV generation to the substation load in each period of the year. The loads, relative to the substation capacities, are shown in Figure 43 for the maximum load day of the year. This data is calculated for all hours of all days of the year for the substation.

Figure 43 Projected load for WBE ZSS at the maximum load day in 2017



WBE has three transformers. In the N-1 case the load transfer capability is included and this is notionally taken as a fourth failure path. The unreliability per transformer is calculated from the mean-time-to-failure and mean-time-to-repair data as 0.22%/transformer/year. The total unreliability for four failure paths is estimated as 0.865% of each year. Consequently the calculations for WBE apply the N capacity for (1-0.865%) of hours and the N-1+load transfer capacity for 0.865% of hours in the year.

The quantity of energy-at-risk calculated in the "with" and "without" cases can be assessed for each of the three augmentation scenarios:

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- No augmentation
- First augmentation, and
- First plus second augmentation

These energy a risk quantities are calculated for each of the 50th percentile and 10the percentile load cases.

The energy at risk quantities are combined using 30% x the 10th percentile and 70% x the 50th percentile weightings.

The pre-tax-real equivalent WACC to the nominal vanilla WACC of 6.11% is 4.79%[26]. The annualised cost of augmentation 1 over its life is calculated as $110,k/year including an adjustment of 2% for opex. The annualised cost of augmentation 2 is $327.5k/y on the same basis. The values calculated are shown in Table 13.

Table 13 Calculated energy at risk and augmentation costs for WBE ZSS in 2017 (existing PV)

	With DG			Without DG		
Augmentations	No	1st	1st+2nd	No	1st	1st+2nd
Weighted MWh/y	5	1	0	33	10	0
VCR cost/y	179,849	46,747	0	1,150,709	344,814	0
Capex+opex $/y	0	110,039	437,568	0	110,039	437,568
Capex+opex+VCR $/y	179,849	156,786	437,568	1,150,709	454,854	437,568
Least cost $/y		156,786			437,568	

With the PV, the least cost is with the first augmentation. The cost is $156.8k/year. If the PV did not exist the least cost would be with both the first and second augmentations in place, being $437.6k/y. The VCR cost (or energy at risk cost) is $46.7k/y and $0k/y respectively remaining after the relevant augmentations are undertaken.

The benefit provided by the PV to the network at WBE ZSS in 2017 is thus $437.6k - $156.8k = $280.8k/y. Per unit of PV capacity this would be $10.78/kW/year.

Values are calculated for the benefits provided at the subtransmission level and at the terminal station level using similar calculations and the total value is the sum of these benefits.

[26] Using a CPI of 2.5% and an effective tax rate of 24%.

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Appendix B. Results detail

Table 14 Existing PV DG in 2017

			$/kW, 2017				DG MW, 2017	$1000/y, 2017			
DNSP	ZSS	ZSS Name	Total	ZSS	Sub-trans	TS		Total	ZSS	Sub-trans	TS
Powercor	AC	Altona Chemicals	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	AL	Altona	0.00	0.00	0.00	0.00	2.9	0.0	0.0	0.0	0.0
Powercor	ART	Ararat	0.01	0.00	0.00	0.01	2.7	0.0	0.0	0.0	0.0
Powercor	BAN	Ballarat North	0.01	0.00	0.00	0.01	16.1	0.2	0.0	0.0	0.2
Powercor	BAS	Ballarat South	0.38	0.00	0.37	0.01	17.7	6.7	0.0	6.5	0.2
Powercor	BBD	Boundary Bend	0.60	0.00	0.00	0.60	0.1	0.1	0.0	0.0	0.1
Powercor	BGO	Bendigo	0.42	0.14	0.00	0.28	9.5	3.9	1.3	0.0	2.6
Powercor	BMH	Bacchus Marsh	0.00	0.00	0.00	0.00	8.4	0.0	0.0	0.0	0.0
Powercor	CDN	Camperdown	1.05	0.00	0.00	1.05	2.4	2.5	0.0	0.0	2.5
Powercor	CHA	Cohuna	0.00	0.00	0.00	0.00	3.2	0.0	0.0	0.0	0.0
Powercor	CHM	Charam	0.00	0.00	0.00	0.00	0.6	0.0	0.0	0.0	0.0
Powercor	CLC	Colac	0.00	0.00	0.00	0.00	5.7	0.0	0.0	0.0	0.0
Powercor	CME	Cobram East	0.00	0.00	0.00	0.00	7.9	0.0	0.0	0.0	0.0
Powercor	CMN	Castlemaine	0.32	0.00	0.04	0.28	8.8	2.8	0.0	0.3	2.5
Powercor	COB	Cobden	1.05	0.00	0.00	1.05	0.1	0.1	0.0	0.0	0.1
Powercor	CRO	Corio	0.00	0.00	0.00	0.00	3.9	0.0	0.0	0.0	0.0
Powercor	CTN	Charlton	0.28	0.00	0.00	0.28	5.3	1.5	0.0	0.0	1.5
Powercor	DDL	Drysdale	0.66	0.50	0.16	0.00	16.5	10.9	8.2	2.7	0.0
Powercor	DLF	Docklands	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	ECA	Echuca	6.61	6.61	0.00	0.00	9.0	59.4	59.4	0.0	0.0
Powercor	EHK	Eaglehawk	0.47	0.19	0.00	0.28	11.0	5.2	2.1	0.0	3.1
Powercor	FNS	Ford North Shore	0.00	0.00	0.00	0.00	7.1	0.0	0.0	0.0	0.0
Powercor	GB	Geelong B	0.00	0.00	0.00	0.00	0.5	0.0	0.0	0.0	0.0
Powercor	GCY	Geelong City	0.10	0.10	0.00	0.00	2.8	0.3	0.3	0.0	0.0
Powercor	GL	Geelong	0.11	0.11	0.00	0.00	12.4	1.3	1.3	0.0	0.0
Powercor	GLE	Geelong East	0.00	0.00	0.00	0.00	10.0	0.0	0.0	0.0	0.0
Powercor	GSB	Gisborne	9.48	0.00	0.00	9.48	6.6	62.5	0.0	0.0	62.5
Powercor	HSM	Horsham	0.00	0.00	0.00	0.00	11.2	0.0	0.0	0.0	0.0
Powercor	HTN	Hamilton	1.05	0.00	0.00	1.05	5.2	5.5	0.0	0.0	5.5
Powercor	KRT	Koroit	1.05	0.00	0.00	1.05	3.2	3.3	0.0	0.0	3.3
Powercor	KYM	Kyabram	0.00	0.00	0.00	0.00	8.0	0.0	0.0	0.0	0.0
Powercor	LV	Laverton	6.37	4.68	0.00	1.69	29.2	185.8	136.6	0.0	49.2
Powercor	LVN	Laverton North 11	1.69	0.00	0.00	1.69	0.0	0.0	0.0	0.0	0.0

			$/kW, 2017				DG MW, 2017	$1000/y, 2017			
DNSP	ZSS	ZSS Name	Total	ZSS	Sub-trans	TS		Total	ZSS	Sub-trans	TS
	11										
Powercor	LVN 22	Laverton North 22	1.69	0.00	0.00	1.69	2.5	4.2	0.0	0.0	4.2
Powercor	MBN	Merbein	0.60	0.00	0.00	0.60	6.7	4.0	0.0	0.0	4.0
Powercor	MDA	Mildura	0.78	0.18	0.00	0.60	7.6	6.0	1.4	0.0	4.6
Powercor	MLN	Melton	9.48	0.00	0.00	9.48	15.4	146.1	0.0	0.0	146.1
Powercor	MNA	Mooroopna	1.27	1.27	0.00	0.00	7.0	9.0	8.9	0.0	0.0
Powercor	MRO	Maryborough	1.30	0.55	0.47	0.28	7.0	9.1	3.9	3.3	1.9
Powercor	NHL	Nhill	0.02	0.02	0.00	0.00	2.7	0.1	0.1	0.0	0.0
Powercor	NKA	Numurkah	0.05	0.05	0.00	0.00	7.5	0.4	0.4	0.0	0.0
Powercor	OYN	Ouyen	0.00	0.00	0.00	0.00	1.9	0.0	0.0	0.0	0.0
Powercor	PLD	Portland	1.05	0.00	0.00	1.05	4.1	4.3	0.0	0.0	4.3
Powercor	RVL	Robinvale	0.60	0.00	0.00	0.60	1.2	0.7	0.0	0.0	0.7
Powercor	SA	St Albans	12.63	3.15	0.00	9.48	17.2	216.7	54.0	0.0	162.7
Powercor	SHL	Swan Hill	5.06	5.05	0.00	0.00	7.0	35.5	35.5	0.0	0.0
Powercor	SHN	Shepparton North	0.76	0.76	0.00	0.00	6.6	5.0	5.0	0.0	0.0
Powercor	SHP	Stanhope	0.00	0.00	0.00	0.00	4.5	0.0	0.0	0.0	0.0
Powercor	SSE	Sunshine East	9.64	0.16	0.00	9.48	7.3	69.9	1.2	0.0	68.8
Powercor	STL	Stawell	0.06	0.06	0.00	0.00	3.0	0.2	0.2	0.0	0.0
Powercor	STN	Shepparton	0.00	0.00	0.00	0.00	8.0	0.0	0.0	0.0	0.0
Powercor	SU	Sunshine	13.24	3.76	0.00	9.48	16.3	215.7	61.2	0.0	154.5
Powercor	TRG	Terang	1.05	0.00	0.00	1.05	3.0	3.2	0.0	0.0	3.2
Powercor	WBE	Werribee	12.47	10.78	0.00	1.69	26.1	324.8	280.8	0.0	44.0
Powercor	WBL	Warrnambool	1.05	0.00	0.00	1.05	5.7	5.9	0.0	0.0	5.9
Powercor	WIN	Winchelsea	0.00	0.00	0.00	0.00	2.5	0.0	0.0	0.0	0.0
Powercor	WMN	Wemen	4.19	4.19	0.00	0.00	0.1	0.3	0.3	0.0	0.0
Powercor	WND	Woodend	9.48	0.00	0.00	9.48	11.6	110.0	0.0	0.0	110.0
Powercor	WPD	Waurn Ponds	0.45	0.45	0.00	0.00	16.3	7.4	7.4	0.0	0.0
CitiPower	AP	Albert Park	0.00	0.00	0.00	0.00	1.7	0.0	0.0	0.0	0.0
CitiPower	AR	Armadale	1.64	0.00	0.00	1.64	0.8	1.3	0.0	0.0	1.3
CitiPower	B	Collingwood	1.64	0.00	0.00	1.64	0.9	1.4	0.0	0.0	1.4
CitiPower	BC	Balaclava	1.64	0.00	0.00	1.64	1.2	1.9	0.0	0.0	1.9
CitiPower	BK	Brunswick	0.00	0.00	0.00	0.00	1.1	0.0	0.0	0.0	0.0
CitiPower	BQ	Bouverie Queensberry	1.64	0.00	0.00	1.64	0.7	1.1	0.0	0.0	1.1
CitiPower	BS/BQ	Bouverie St/Bouverie	1.64	0.00	0.00	1.64	0.0	0.0	0.0	0.0	0.0

			$/kW, 2017				DG MW, 2017	$1000/y, 2017			
DNSP	ZSS	ZSS Name	Total	ZSS	Sub-trans	TS		Total	ZSS	Sub-trans	TS
		Queensberry									
CitiPower	C	Brunswick	0.00	0.00	0.00	0.00	0.7	0.0	0.0	0.0	0.0
CitiPower	CL	Camberwell	1.64	0.00	0.00	1.64	1.7	2.8	0.0	0.0	2.8
CitiPower	CW	Collingwood	3.92	2.28	0.00	1.64	0.8	3.3	1.9	0.0	1.4
CitiPower	DA	Dock Area	0.00	0.00	0.00	0.00	0.2	0.0	0.0	0.0	0.0
CitiPower	E	Fishermans Bend also	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
CitiPower	F	Fitzroy	0.00	0.00	0.00	0.00	1.8	0.0	0.0	0.0	0.0
CitiPower	FB	Fishermans Bend	0.00	0.00	0.00	0.00	0.1	0.0	0.0	0.0	0.0
CitiPower	FR	Flinders/Ramsden	1.94	0.30	0.00	1.64	0.1	0.2	0.0	0.0	0.2
CitiPower	J	Spencer Street	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
CitiPower	JA	Little Bourke Street	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
CitiPower	L	Deepdene	0.00	0.00	0.00	0.00	3.0	0.0	0.0	0.0	0.0
CitiPower	LQ	Little Queen	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
CitiPower	LS	Laurens Street	0.00	0.00	0.00	0.00	1.0	0.0	0.0	0.0	0.0
CitiPower	MG	Montague	0.00	0.00	0.00	0.00	0.3	0.0	0.0	0.0	0.0
CitiPower	MP	McIllwraith Place	1.64	0.00	0.00	1.64	0.5	0.8	0.0	0.0	0.8
CitiPower	NC	Northcote	0.07	0.07	0.00	0.00	4.8	0.3	0.3	0.0	0.0
CitiPower	NR	Nth Richmond	1.64	0.00	0.00	1.64	3.3	5.4	0.0	0.0	5.4
CitiPower	PM	Port Melbourne	0.00	0.00	0.00	0.00	0.3	0.0	0.0	0.0	0.0
CitiPower	PR	Prahran	1.64	0.00	0.00	1.64	0.0	0.0	0.0	0.0	0.0
CitiPower	Q	Kew	0.10	0.10	0.00	0.00	2.1	0.2	0.2	0.0	0.0
CitiPower	R	Richmond	4.61	2.97	0.00	1.64	0.5	2.1	1.4	0.0	0.7
CitiPower	RD	Riversdale	0.06	0.06	0.00	0.00	2.6	0.2	0.2	0.0	0.0
CitiPower	RP	Russell Place	1.64	0.00	0.00	1.64	0.0	0.0	0.0	0.0	0.0
CitiPower	SB	Southbank	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
CitiPower	SK	St Kilda	1.66	0.02	0.00	1.64	0.5	0.8	0.0	0.0	0.8
CitiPower	SO	South Melbourne	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
CitiPower	TK	Toorak	1.64	0.00	0.00	1.64	1.0	1.7	0.0	0.0	1.7
CitiPower	TP	Tavistock Place	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
CitiPower	VM	Victoria Market	0.00	0.00	0.00	0.00	0.3	0.0	0.0	0.0	0.0
CitiPower	WA	Celestial Avenue	0.05	0.05	0.00	0.00	0.1	0.0	0.0	0.0	0.0
CitiPower	WB	West Brunswick	0.11	0.11	0.00	0.00	2.7	0.3	0.3	0.0	0.0
CitiPower	WG	Westgate	0.00	0.00	0.00	0.00	0.7	0.0	0.0	0.0	0.0
UE	BH	Box Hill	0.00	0.00	0.00	0.00	3.6	0.0	0.0	0.0	0.0
UE	BR	Beaumaris	0.00	0.00	0.00	0.00	2.2	0.0	0.0	0.0	0.0

			$/kW, 2017				DG MW, 2017	$1000/y, 2017			
DNSP	ZSS	ZSS Name	Total	ZSS	Sub-trans	TS		Total	ZSS	Sub-trans	TS
UE	BT	Bentleigh	0.00	0.00	0.00	0.00	2.5	0.0	0.0	0.0	0.0
UE	BU	Bulleen	0.00	0.00	0.00	0.00	2.8	0.0	0.0	0.0	0.0
UE	BW	Burwood	0.00	0.00	0.00	0.00	2.5	0.0	0.0	0.0	0.0
UE	CDA	Clarinda	0.00	0.00	0.00	0.00	3.8	0.0	0.0	0.0	0.0
UE	CFD	Caulfield	0.30	0.30	0.00	0.00	2.5	0.8	0.8	0.0	0.0
UE	CM	Cheltenham	0.00	0.00	0.00	0.00	0.5	0.0	0.0	0.0	0.0
UE	CRM	Carrum	0.00	0.00	0.00	0.00	11.7	0.0	0.0	0.0	0.0
UE	DC	Doncaster	0.01	0.01	0.00	0.00	7.4	0.1	0.1	0.0	0.0
UE	DMA	Dromana	0.04	0.00	0.04	0.00	5.6	0.2	0.0	0.2	0.0
UE	DN	Dandenong	0.00	0.00	0.00	0.00	6.9	0.0	0.0	0.0	0.0
UE	DSH	Dandenong South	0.00	0.00	0.00	0.00	2.5	0.0	0.0	0.0	0.0
UE	DVY	Dandenong Valley	0.00	0.00	0.00	0.00	2.4	0.0	0.0	0.0	0.0
UE	EB	East Burwood	0.00	0.00	0.00	0.00	5.6	0.0	0.0	0.0	0.0
UE	EL	Elsternwick	0.00	0.00	0.00	0.00	1.0	0.0	0.0	0.0	0.0
UE	EM	East Malvern	0.00	0.00	0.00	0.00	3.1	0.0	0.0	0.0	0.0
UE	EW	Elwood	1.64	0.00	0.00	1.64	0.9	1.5	0.0	0.0	1.5
UE	FSH	Frankston South	0.00	0.00	0.00	0.00	10.6	0.0	0.0	0.0	0.0
UE	FTN	Frankston	0.00	0.00	0.00	0.00	3.1	0.0	0.0	0.0	0.0
UE	GW	Glen Waverley	0.00	0.00	0.00	0.00	5.5	0.0	0.0	0.0	0.0
UE	HGS	Hastings	0.00	0.00	0.00	0.00	8.3	0.0	0.0	0.0	0.0
UE	HT	Heatherton	0.00	0.00	0.00	0.00	1.8	0.0	0.0	0.0	0.0
UE	K	Gardiner	1.64	0.00	0.00	1.64	1.6	2.6	0.0	0.0	2.6
UE	KBH	Keysborough	0.00	0.00	0.00	0.00	1.3	0.0	0.0	0.0	0.0
UE	LD	Lyndale	0.00	0.00	0.00	0.00	8.6	0.0	0.0	0.0	0.0
UE	LWN	Langwarrin	0.00	0.00	0.00	0.00	5.3	0.0	0.0	0.0	0.0
UE	M	Mentone	0.00	0.00	0.00	0.00	2.6	0.0	0.0	0.0	0.0
UE	MC	Mordialloc	0.00	0.00	0.00	0.00	4.4	0.0	0.0	0.0	0.0
UE	MGE	Mulgrave	0.00	0.00	0.00	0.00	6.1	0.0	0.0	0.0	0.0
UE	MR	Moorabbin	0.00	0.00	0.00	0.00	3.1	0.0	0.0	0.0	0.0
UE	MTN	Mornington	0.00	0.00	0.00	0.00	8.7	0.0	0.0	0.0	0.0
UE	NB	North Brighton	0.00	0.00	0.00	0.00	2.1	0.0	0.0	0.0	0.0
UE	NO	Notting Hill	0.01	0.01	0.00	0.00	0.7	0.0	0.0	0.0	0.0
UE	NP	Noble Park	0.00	0.00	0.00	0.00	5.3	0.0	0.0	0.0	0.0
UE	NW	Nunawading	0.00	0.00	0.00	0.00	5.4	0.0	0.0	0.0	0.0
UE	OAK	Oakleigh	0.00	0.00	0.00	0.00	2.4	0.0	0.0	0.0	0.0
UE	OE	Oakleigh East	0.00	0.00	0.00	0.00	0.8	0.0	0.0	0.0	0.0

			$/kW, 2017				DG MW, 2017	$1000/y, 2017			
DNSP	ZSS	ZSS Name	Total	ZSS	Sub-trans	TS		Total	ZSS	Sub-trans	TS
UE	OR	Ormond	0.00	0.00	0.00	0.00	3.5	0.0	0.0	0.0	0.0
UE	RBD	Rosebud	0.08	0.00	0.08	0.00	8.9	0.7	0.0	0.7	0.0
UE	SH	Surrey Hills	0.00	0.00	0.00	0.00	0.6	0.0	0.0	0.0	0.0
UE	SR	Sandringham	0.00	0.00	0.00	0.00	1.8	0.0	0.0	0.0	0.0
UE	SS	Springvale South	0.00	0.00	0.00	0.00	4.0	0.0	0.0	0.0	0.0
UE	STO	Sorrento	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	SV/SVW	Springvale/Springvale West	0.00	0.00	0.00	0.00	4.0	0.0	0.0	0.0	0.0
UE	WD	West Doncaster	0.00	0.00	0.00	0.00	1.7	0.0	0.0	0.0	0.0
Jemena	AW	Airport West	9.48	0.00	0.00	9.48	8.2	77.4	0.0	0.0	77.4
Jemena	BY	Braybrook	9.48	0.00	0.00	9.48	2.7	25.7	0.0	0.0	25.7
Jemena	BD	Broadmeadows	0.00	0.00	0.00	0.00	5.6	0.0	0.0	0.0	0.0
Jemena	BMS	Broadmeadows South	0.00	0.00	0.00	0.00	0.7	0.0	0.0	0.0	0.0
Jemena	CN	Coburg North	0.00	0.00	0.00	0.00	5.6	0.0	0.0	0.0	0.0
Jemena	CS	Coburg South	0.03	0.03	0.00	0.00	5.1	0.2	0.2	0.0	0.0
Jemena	COO	Coolaroo	0.00	0.00	0.00	0.00	12.4	0.0	0.0	0.0	0.0
Jemena	EP-A	East Preston Switch House A	0.00	0.00	0.00	0.00	0.4	0.0	0.0	0.0	0.0
Jemena	EP-B	East Preston Switch House B	0.00	0.00	0.00	0.00	0.4	0.0	0.0	0.0	0.0
Jemena	EPN	East Preston (66/22 kV)	0.00	0.00	0.00	0.00	0.6	0.0	0.0	0.0	0.0
Jemena	ES	Essendon	9.48	0.00	0.00	9.48	3.6	34.1	0.0	0.0	34.1
Jemena	FF	Fairfield	0.00	0.00	0.00	0.00	1.7	0.0	0.0	0.0	0.0
Jemena	FT	Flemington	0.00	0.00	0.00	0.00	2.0	0.0	0.0	0.0	0.0
Jemena	FE	Footscray East	0.00	0.00	0.00	0.00	2.2	0.0	0.0	0.0	0.0
Jemena	FW	Footscray West	0.00	0.00	0.00	0.00	3.0	0.0	0.0	0.0	0.0
Jemena	HB	Heidelberg	0.00	0.00	0.00	0.00	2.3	0.0	0.0	0.0	0.0
Jemena	NT	Newport	0.00	0.00	0.00	0.00	3.0	0.0	0.0	0.0	0.0
Jemena	NS	North Essendon	0.00	0.00	0.00	0.00	1.7	0.0	0.0	0.0	0.0
Jemena	NH	North Heidelberg	0.00	0.00	0.00	0.00	4.9	0.0	0.0	0.0	0.0
Jemena	PV	Pascoe Vale	9.48	0.00	0.00	9.48	4.5	42.6	0.0	0.0	42.6
Jemena	P	Preston	0.00	0.00	0.00	0.00	0.3	0.0	0.0	0.0	0.0
Jemena	ST	Somerton	0.23	0.00	0.00	0.23	8.7	2.0	0.0	0.0	2.0
Jemena	SBY	Sunbury	9.48	0.00	0.00	9.48	8.5	80.9	0.0	0.0	80.9
Jemena	SHM	Sydenham	9.49	0.01	0.00	9.48	7.7	73.1	0.1	0.0	73.0
Jemena	TH	Tottenham	0.00	0.00	0.00	0.00	0.9	0.0	0.0	0.0	0.0

			$/kW, 2017				DG MW, 2017	$1000/y, 2017			
DNSP	ZSS	ZSS Name	Total	ZSS	Sub-trans	TS		Total	ZSS	Sub-trans	TS
Jemena	TMA	Tullamarine	9.48	0.00	0.00	9.48	0.9	8.9	0.0	0.0	8.9
Jemena	YVE	Yarraville	0.00	0.00	0.00	0.00	1.8	0.0	0.0	0.0	0.0
AusNet	BDL	Bairnsdale	0.91	0.00	0.05	0.86	20.3	18.6	0.0	1.1	17.4
AusNet	BGE	Belgrave	0.00	0.00	0.00	0.00	6.3	0.0	0.0	0.0	0.0
AusNet	BN	Benalla	0.93	0.93	0.00	0.00	6.7	6.3	6.3	0.0	0.0
AusNet	BRA	Boronia	0.00	0.00	0.00	0.00	5.8	0.0	0.0	0.0	0.0
AusNet	BRT	Bright	0.00	0.00	0.00	0.00	0.6	0.0	0.0	0.0	0.0
AusNet	BWA	Barnawatha	35.45	0.00	21.82	13.62	4.5	158.0	0.0	97.3	60.7
AusNet	BWN	Berwick North	0.34	0.00	0.34	0.00	2.9	1.0	0.0	1.0	0.0
AusNet	BWR	Bayswater	0.00	0.00	0.00	0.00	4.7	0.0	0.0	0.0	0.0
AusNet	CF	Clover Flat	0.00	0.00	0.00	0.00	4.7	0.0	0.0	0.0	0.0
AusNet	CLN	Clyde North	9.40	9.05	0.34	0.00	29.7	279.4	269.2	10.2	0.0
AusNet	CNR	Cann River	0.95	0.00	0.09	0.86	2.2	2.1	0.0	0.2	1.9
AusNet	CPK	Chirnside Park	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	CRE	Cranbourne	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	CYN	Croydon	0.00	0.00	0.00	0.00	7.9	0.0	0.0	0.0	0.0
AusNet	DRN	Doreen	1.34	1.11	0.00	0.23	3.7	5.0	4.2	0.0	0.9
AusNet	ELM	Eltham	0.00	0.00	0.00	0.00	9.9	0.0	0.0	0.0	0.0
AusNet	EPG	Epping	0.23	0.00	0.00	0.23	2.0	0.5	0.0	0.0	0.5
AusNet	FGY	Ferntree Gully	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	FTR	Foster	0.86	0.00	0.00	0.86	6.7	5.8	0.0	0.0	5.8
AusNet	HPK	Hampton Park	0.00	0.00	0.00	0.00	10.7	0.0	0.0	0.0	0.0
AusNet	KLK	Kinglake	5.19	0.37	4.58	0.23	8.6	44.5	3.2	39.3	2.0
AusNet	KLO	Kalkallo	0.23	0.00	0.00	0.23	0.0	0.0	0.0	0.0	0.0
AusNet	KMS	Kilmore South	4.81	0.00	4.58	0.23	12.8	61.7	0.0	58.7	2.9
AusNet	LDL	Lilydale	0.00	0.00	0.00	0.00	6.4	0.0	0.0	0.0	0.0
AusNet	LGA	Leongatha	0.86	0.00	0.00	0.86	5.5	4.7	0.0	0.0	4.7
AusNet	LLG	Lang Lang	0.34	0.00	0.34	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	LYD	Lysterfield	0.34	0.00	0.34	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	MBY	Mt Beauty	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	MDI	Murrindindi	4.81	0.00	4.58	0.23	2.2	10.8	0.0	10.3	0.5
AusNet	MFA	Maffra	0.91	0.00	0.05	0.86	5.1	4.7	0.0	0.3	4.4
AusNet	MJG	Merrijig	2.81	0.00	2.81	0.00	4.4	12.3	0.0	12.3	0.0
AusNet	MOE	Moe	0.86	0.00	0.00	0.86	8.7	7.5	0.0	0.0	7.5
AusNet	MSD	Mansfield	0.00	0.00	0.00	0.00	0.1	0.0	0.0	0.0	0.0
AusNet	MWT	Morwell	0.86	0.00	0.00	0.86	0.0	0.0	0.0	0.0	0.0

			$/kW, 2017				DG MW, 2017	$1000/y, 2017			
DNSP	ZSS	ZSS Name	Total	ZSS	Sub-trans	TS		Total	ZSS	Sub-trans	TS
AusNet	MYT	Myrtleford	0.00	0.00	0.00	0.00	7.5	0.0	0.0	0.0	0.0
AusNet	NLA	Newmerella	0.86	0.00	0.00	0.86	1.5	1.3	0.0	0.0	1.3
AusNet	NRN	Narre Warren	0.34	0.00	0.34	0.00	13.7	4.7	0.0	4.7	0.0
AusNet	OFR	Officer	0.34	0.00	0.34	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	PHI	Phillip Island	5.54	0.01	4.67	0.86	5.8	32.3	0.1	27.2	5.0
AusNet	PHM	Pakenham	0.34	0.00	0.34	0.00	18.9	6.5	0.0	6.5	0.0
AusNet	RUBA	Rubicon 'A'	4.81	0.00	4.58	0.23	0.0	0.0	0.0	0.0	0.0
AusNet	RWN	Ringwood North	0.00	0.00	0.00	0.00	14.1	0.0	0.0	0.0	0.0
AusNet	SLE	Sale	0.91	0.00	0.05	0.86	3.0	2.7	0.0	0.2	2.6
AusNet	SMG	South Morang	0.23	0.00	0.00	0.23	0.0	0.0	0.0	0.0	0.0
AusNet	SMR	Seymour	4.81	0.00	4.58	0.23	8.0	38.7	0.0	36.8	1.8
AusNet	TGN	Traralgon	0.91	0.00	0.05	0.86	10.8	9.8	0.0	0.6	9.2
AusNet	TT	Thomastown	18.11	18.11	0.00	0.00	10.3	187.3	187.3	0.0	0.0
AusNet	WGI	Wonthaggi	1.77	0.11	0.80	0.86	10.6	18.7	1.2	8.5	9.1
AusNet	WGL	Warragul	1.12	0.26	0.00	0.86	14.8	16.7	3.9	0.0	12.7
AusNet	WN	Wangaratta	0.03	0.03	0.00	0.00	4.8	0.1	0.1	0.0	0.0
AusNet	WO	Wodonga	13.93	0.00	0.30	13.62	11.5	159.8	0.0	3.5	156.4
AusNet	WT	Watsonia	0.00	0.00	0.00	0.00	8.6	0.0	0.0	0.0	0.0
AusNet	WYK	Woori Yallock	0.00	0.00	0.00	0.00	19.6	0.0	0.0	0.0	0.0
		Average	**2.76**	**1.06**	**0.31**	**1.40**					
		Total					**1,088**	**3,006**	**1,150**	**332.4**	**1,524**

Table 15 Existing dispatchable DG, 2017

			$/kW, 2017				DG MW, 2017	$1000/y, 2017			
DNSP	ZSS	ZSS Name	Total	ZSS	Sub-trans	TS		Total	ZSS	Sub-trans	TS
Powercor	AC	Altona Chemicals	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	AL	Altona	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	ART	Ararat	0.05	0.00	0.00	0.05	0.0	0.0	0.0	0.0	0.0
Powercor	BAN	Ballarat North	0.05	0.00	0.00	0.05	2.6	0.1	0.0	0.0	0.1
Powercor	BAS	Ballarat South	0.96	0.00	0.91	0.05	1.2	1.1	0.0	1.1	0.1
Powercor	BBD	Boundary Bend	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	BGO	Bendigo	0.67	0.00	0.00	0.67	0.0	0.0	0.0	0.0	0.0

			$/kW, 2017				DG MW, 2017	$1000/y, 2017			
DNSP	ZSS	ZSS Name	Total	ZSS	Sub-trans	TS		Total	ZSS	Sub-trans	TS
Powercor	BMH	Bacchus Marsh	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	CDN	Camperdown	57.22	0.00	0.00	57.22	0.0	0.0	0.0	0.0	0.0
Powercor	CHA	Cohuna	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	CHM	Charam	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	CLC	Colac	0.00	0.00	0.00	0.00	2.9	0.0	0.0	0.0	0.0
Powercor	CME	Cobram East	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	CMN	Castlemaine	0.67	0.00	0.00	0.67	0.0	0.0	0.0	0.0	0.0
Powercor	COB	Cobden	57.22	0.00	0.00	57.22	0.0	0.0	0.0	0.0	0.0
Powercor	CRO	Corio	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	CTN	Charlton	0.67	0.00	0.00	0.67	0.0	0.0	0.0	0.0	0.0
Powercor	DDL	Drysdale	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	DLF	Docklands	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	ECA	Echuca	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	EHK	Eaglehawk	1.17	0.50	0.01	0.67	0.8	0.9	0.4	0.0	0.5
Powercor	FNS	Ford North Shore	0.00	0.00	0.00	0.00	1.0	0.0	0.0	0.0	0.0
Powercor	GB	Geelong B	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	GCY	Geelong City	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	GL	Geelong	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	GLE	Geelong East	0.00	0.00	0.00	0.00	1.2	0.0	0.0	0.0	0.0
Powercor	GSB	Gisborne	37.88	0.00	0.00	37.88	0.0	0.0	0.0	0.0	0.0
Powercor	HSM	Horsham	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	HTN	Hamilton	57.22	0.00	0.00	57.22	0.0	0.0	0.0	0.0	0.0
Powercor	KRT	Koroit	57.22	0.00	0.00	57.22	0.0	0.0	0.0	0.0	0.0
Powercor	KYM	Kyabram	0.00	0.00	0.00	0.00	0.5	0.0	0.0	0.0	0.0
Powercor	LV	Laverton	36.95	31.04	0.00	5.91	4.4	162.6	136.6	0.0	26.0
Powercor	LVN 11	Laverton North 11	5.91	0.00	0.00	5.91	0.0	0.0	0.0	0.0	0.0
Powercor	LVN 22	Laverton North 22	5.91	0.00	0.00	5.91	0.0	0.0	0.0	0.0	0.0
Powercor	MBN	Merbein	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	MDA	Mildura	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	MLN	Melton	37.88	0.00	0.00	37.88	1.0	39.0	0.0	0.0	39.0
Powercor	MNA	Mooroopna	4.66	4.64	0.02	0.00	1.0	4.7	4.6	0.0	0.0
Powercor	MRO	Maryborough	0.67	0.00	0.00	0.67	0.0	0.0	0.0	0.0	0.0
Powercor	NHL	Nhill	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	NKA	Numurkah	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	OYN	Ouyen	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0

			$/kW, 2017				DG MW, 2017	$1000/y, 2017			
DNSP	ZSS	ZSS Name	Total	ZSS	Sub-trans	TS		Total	ZSS	Sub-trans	TS
Powercor	PLD	Portland	57.22	0.00	0.00	57.22	0.0	0.0	0.0	0.0	0.0
Powercor	RVL	Robinvale	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	SA	St Albans	37.88	0.00	0.00	37.88	0.0	0.0	0.0	0.0	0.0
Powercor	SHL	Swan Hill	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	SHN	Shepparton North	1.55	1.55	0.00	0.00	1.0	1.6	1.6	0.0	0.0
Powercor	SHP	Stanhope	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	SSE	Sunshine East	37.88	0.00	0.00	37.88	0.0	0.0	0.0	0.0	0.0
Powercor	STL	Stawell	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	STN	Shepparton	0.01	0.00	0.01	0.00	0.8	0.0	0.0	0.0	0.0
Powercor	SU	Sunshine	37.88	0.00	0.00	37.88	0.0	0.0	0.0	0.0	0.0
Powercor	TRG	Terang	57.22	0.00	0.00	57.22	0.0	0.0	0.0	0.0	0.0
Powercor	WBE	Werribee	25.53	19.62	0.00	5.91	1.8	46.0	35.3	0.0	10.6
Powercor	WBL	Warrnambool	57.22	0.00	0.00	57.22	1.5	85.8	0.0	0.0	85.8
Powercor	WIN	Winchelsea	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	WMN	Wemen	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Powercor	WND	Woodend	37.88	0.00	0.00	37.88	0.0	0.0	0.0	0.0	0.0
Powercor	WPD	Waurn Ponds	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
CitiPower	AP	Albert Park	0.00	0.00	0.00	0.00	0.8	0.0	0.0	0.0	0.0
CitiPower	AR	Armadale	8.13	0.00	0.00	8.13	0.0	0.0	0.0	0.0	0.0
CitiPower	B	Collingwood	8.13	0.00	0.00	8.13	0.0	0.0	0.0	0.0	0.0
CitiPower	BC	Balaclava	8.13	0.00	0.00	8.13	0.0	0.0	0.0	0.0	0.0
CitiPower	BK	Brunswick	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
CitiPower	BQ	Bouverie Queensberry	8.13	0.00	0.00	8.13	0.4	3.2	0.0	0.0	3.2
CitiPower	BS/BQ	Bouverie St/Bouverie Queensberry	8.13	0.00	0.00	8.13	14.7	119.5	0.0	0.0	119.5
CitiPower	C	Brunswick	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
CitiPower	CL	Camberwell	8.13	0.00	0.00	8.13	0.1	1.1	0.0	0.0	1.1
CitiPower	CW	Collingwood	16.92	8.80	0.00	8.13	0.1	1.0	0.5	0.0	0.5
CitiPower	DA	Dock Area	1.63	1.13	0.50	0.00	2.4	3.9	2.7	1.2	0.0
CitiPower	E	Fishermans Bend also	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
CitiPower	F	Fitzroy	0.00	0.00	0.00	0.00	0.1	0.0	0.0	0.0	0.0
CitiPower	FB	Fishermans Bend	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
CitiPower	FR	Flinders/Ramsden	9.22	1.10	0.00	8.13	0.3	3.0	0.4	0.0	2.6
CitiPower	J	Spencer Street	0.00	0.00	0.00	0.00	0.4	0.0	0.0	0.0	0.0

			$/kW, 2017				DG MW, 2017	$1000/y, 2017			
DNSP	ZSS	ZSS Name	Total	ZSS	Sub-trans	TS		Total	ZSS	Sub-trans	TS
CitiPower	JA	Little Bourke Street	0.00	0.00	0.00	0.00	3.7	0.0	0.0	0.0	0.0
CitiPower	L	Deepdene	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
CitiPower	LQ	Little Queen	0.00	0.00	0.00	0.00	0.2	0.0	0.0	0.0	0.0
CitiPower	LS	Laurens Street	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
CitiPower	MG	Montague	0.00	0.00	0.00	0.00	0.8	0.0	0.0	0.0	0.0
CitiPower	MP	McIllwraith Place	8.13	0.00	0.00	8.13	1.2	9.3	0.0	0.0	9.3
CitiPower	NC	Northcote	2.75	2.75	0.00	0.00	0.1	0.3	0.3	0.0	0.0
CitiPower	NR	Nth Richmond	8.13	0.00	0.00	8.13	0.1	0.5	0.0	0.0	0.5
CitiPower	PM	Port Melbourne	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
CitiPower	PR	Prahran	8.13	0.00	0.00	8.13	0.0	0.0	0.0	0.0	0.0
CitiPower	Q	Kew	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
CitiPower	R	Richmond	8.13	0.00	0.00	8.13	0.0	0.0	0.0	0.0	0.0
CitiPower	RD	Riversdale	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
CitiPower	RP	Russell Place	8.13	0.00	0.00	8.13	0.1	0.5	0.0	0.0	0.5
CitiPower	SB	Southbank	0.00	0.00	0.00	0.00	0.7	0.0	0.0	0.0	0.0
CitiPower	SK	St Kilda	8.13	0.00	0.00	8.13	0.0	0.0	0.0	0.0	0.0
CitiPower	SO	South Melbourne	0.00	0.00	0.00	0.00	0.3	0.0	0.0	0.0	0.0
CitiPower	TK	Toorak	8.13	0.00	0.00	8.13	0.1	0.5	0.0	0.0	0.5
CitiPower	TP	Tavistock Place	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
CitiPower	VM	Victoria Market	0.00	0.00	0.00	0.00	0.3	0.0	0.0	0.0	0.0
CitiPower	WA	Celestial Avenue	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
CitiPower	WB	West Brunswick	0.35	0.35	0.00	0.00	0.1	0.0	0.0	0.0	0.0
CitiPower	WG	Westgate	0.00	0.00	0.00	0.00	10.5	0.0	0.0	0.0	0.0
UE	BH	Box Hill	0.00	0.00	0.00	0.00	0.1	0.0	0.0	0.0	0.0
UE	BR	Beaumaris	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	BT	Bentleigh	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	BU	Bulleen	0.00	0.00	0.00	0.00	0.1	0.0	0.0	0.0	0.0
UE	BW	Burwood	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	CDA	Clarinda	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	CFD	Caulfield	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	CM	Cheltenham	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	CRM	Carrum	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	DC	Doncaster	0.13	0.13	0.00	0.00	1.6	0.2	0.2	0.0	0.0
UE	DMA	Dromana	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	DN	Dandenong	0.00	0.00	0.00	0.00	1.8	0.0	0.0	0.0	0.0
UE	DSH	Dandenong South	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0

			$/kW, 2017				DG MW, 2017	$1000/y, 2017			
DNSP	ZSS	ZSS Name	Total	ZSS	Sub-trans	TS		Total	ZSS	Sub-trans	TS
UE	DVY	Dandenong Valley	0.00	0.00	0.00	0.00	0.9	0.0	0.0	0.0	0.0
UE	EB	East Burwood	0.00	0.00	0.00	0.00	0.5	0.0	0.0	0.0	0.0
UE	EL	Elsternwick	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	EM	East Malvern	0.00	0.00	0.00	0.00	1.4	0.0	0.0	0.0	0.0
UE	EW	Elwood	8.13	0.00	0.00	8.13	0.0	0.0	0.0	0.0	0.0
UE	FSH	Frankston South	0.00	0.00	0.00	0.00	0.1	0.0	0.0	0.0	0.0
UE	FTN	Frankston	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	GW	Glen Waverley	0.00	0.00	0.00	0.00	0.6	0.0	0.0	0.0	0.0
UE	HGS	Hastings	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	HT	Heatherton	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	K	Gardiner	8.13	0.00	0.00	8.13	0.0	0.0	0.0	0.0	0.0
UE	KBH	Keysborough	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	LD	Lyndale	0.00	0.00	0.00	0.00	4.1	0.0	0.0	0.0	0.0
UE	LWN	Langwarrin	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	M	Mentone	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	MC	Mordialloc	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	MGE	Mulgrave	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	MR	Moorabbin	0.00	0.00	0.00	0.00	0.2	0.0	0.0	0.0	0.0
UE	MTN	Mornington	0.00	0.00	0.00	0.00	1.6	0.0	0.0	0.0	0.0
UE	NB	North Brighton	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	NO	Notting Hill	0.84	0.84	0.00	0.00	5.0	4.2	4.2	0.0	0.0
UE	NP	Noble Park	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	NW	Nunawading	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	OAK	Oakleigh	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	OE	Oakleigh East	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	OR	Ormond	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	RBD	Rosebud	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	SH	Surrey Hills	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	SR	Sandringham	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
UE	SS	Springvale South	0.00	0.00	0.00	0.00	4.1	0.0	0.0	0.0	0.0
UE	STO	Sorrento	0.00	0.00	0.00	0.00	3.0	0.0	0.0	0.0	0.0
UE	SV/SVW	Springvale/Springvale West	0.00	0.00	0.00	0.00	1.6	0.0	0.0	0.0	0.0
UE	WD	West Doncaster	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Jemena	AW	Airport West	37.88	0.00	0.00	37.88	0.0	0.0	0.0	0.0	0.0
Jemena	BY	Braybrook	37.88	0.00	0.00	37.88	0.3	10.0	0.0	0.0	10.0
Jemena	BD	Broadmeadows	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0

			$/kW, 2017				DG MW, 2017	$1000/y, 2017			
DNSP	ZSS	ZSS Name	Total	ZSS	Sub-trans	TS		Total	ZSS	Sub-trans	TS
Jemena	BMS	Broadmeadows South	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Jemena	CN	Coburg North	0.00	0.00	0.00	0.00	2.6	0.0	0.0	0.0	0.0
Jemena	CS	Coburg South	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Jemena	COO	Coolaroo	0.00	0.00	0.00	0.00	0.2	0.0	0.0	0.0	0.0
Jemena	EP-A	East Preston Switch House A	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Jemena	EP-B	East Preston Switch House B	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Jemena	EPN	East Preston (66/22 kV)	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Jemena	ES	Essendon	37.88	0.00	0.00	37.88	0.0	0.0	0.0	0.0	0.0
Jemena	FF	Fairfield	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Jemena	FT	Flemington	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Jemena	FE	Footscray East	0.00	0.00	0.00	0.00	0.1	0.0	0.0	0.0	0.0
Jemena	FW	Footscray West	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Jemena	HB	Heidelberg	0.00	0.00	0.00	0.00	0.1	0.0	0.0	0.0	0.0
Jemena	NT	Newport	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Jemena	NS	North Essendon	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Jemena	NH	North Heidelberg	0.00	0.00	0.00	0.00	1.5	0.0	0.0	0.0	0.0
Jemena	PV	Pascoe Vale	37.88	0.00	0.00	37.88	0.0	0.0	0.0	0.0	0.0
Jemena	P	Preston	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Jemena	ST	Somerton	0.91	0.00	0.00	0.91	0.0	0.0	0.0	0.0	0.0
Jemena	SBY	Sunbury	37.88	0.00	0.00	37.88	0.0	0.0	0.0	0.0	0.0
Jemena	SHM	Sydenham	37.88	0.00	0.00	37.88	0.0	0.0	0.0	0.0	0.0
Jemena	TH	Tottenham	0.00	0.00	0.00	0.00	3.0	0.0	0.0	0.0	0.0
Jemena	TMA	Tullamarine	37.88	0.00	0.00	37.88	0.0	0.0	0.0	0.0	0.0
Jemena	YVE	Yarraville	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	BDL	Bairnsdale	2.75	0.00	0.41	2.34	0.0	0.0	0.0	0.0	0.0
AusNet	BGE	Belgrave	0.00	0.00	0.00	0.00	3.8	0.0	0.0	0.0	0.0
AusNet	BN	Benalla	6.08	6.08	0.00	0.00	2.0	12.2	12.2	0.0	0.0
AusNet	BRA	Boronia	0.00	0.00	0.00	0.00	2.0	0.0	0.0	0.0	0.0
AusNet	BRT	Bright	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	BWA	Barnawatha	33.50	0.00	0.00	33.50	0.0	0.0	0.0	0.0	0.0
AusNet	BWN	Berwick North	0.92	0.00	0.92	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	BWR	Bayswater	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	CF	Clover Flat	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0

			$/kW, 2017				DG MW, 2017	$1000/y, 2017			
DNSP	ZSS	ZSS Name	Total	ZSS	Sub-trans	TS		Total	ZSS	Sub-trans	TS
AusNet	CLN	Clyde North	0.92	0.00	0.92	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	CNR	Cann River	2.34	0.00	0.00	2.34	0.0	0.0	0.0	0.0	0.0
AusNet	CPK	Chirnside Park	0.00	0.00	0.00	0.00	1.3	0.0	0.0	0.0	0.0
AusNet	CRE	Cranbourne	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	CYN	Croydon	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	DRN	Doreen	0.91	0.00	0.00	0.91	0.0	0.0	0.0	0.0	0.0
AusNet	ELM	Eltham	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	EPG	Epping	0.91	0.00	0.00	0.91	1.8	1.6	0.0	0.0	1.6
AusNet	FGY	Ferntree Gully	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	FTR	Foster	2.34	0.00	0.00	2.34	0.0	0.0	0.0	0.0	0.0
AusNet	HPK	Hampton Park	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	KLK	Kinglake	0.91	0.00	0.00	0.91	0.0	0.0	0.0	0.0	0.0
AusNet	KLO	Kalkallo	0.91	0.00	0.00	0.91	0.0	0.0	0.0	0.0	0.0
AusNet	KMS	Kilmore South	0.91	0.00	0.00	0.91	0.0	0.0	0.0	0.0	0.0
AusNet	LDL	Lilydale	0.00	0.00	0.00	0.00	2.9	0.0	0.0	0.0	0.0
AusNet	LGA	Leongatha	2.34	0.00	0.00	2.34	1.8	4.1	0.0	0.0	4.1
AusNet	LLG	Lang Lang	0.92	0.00	0.92	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	LYD	Lysterfield	1.00	0.08	0.92	0.00	0.2	0.2	0.0	0.2	0.0
AusNet	MBY	Mt Beauty	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	MDI	Murrindindi	0.91	0.00	0.00	0.91	0.0	0.0	0.0	0.0	0.0
AusNet	MFA	Maffra	2.81	0.06	0.41	2.34	3.8	10.7	0.2	1.5	8.9
AusNet	MJG	Merrijig	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	MOE	Moe	2.39	0.03	0.01	2.34	3.3	7.8	0.1	0.0	7.6
AusNet	MSD	Mansfield	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	MWT	Morwell	2.34	0.00	0.00	2.34	2.0	4.6	0.0	0.0	4.6
AusNet	MYT	Myrtleford	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	NLA	Newmerella	2.34	0.00	0.00	2.34	0.0	0.0	0.0	0.0	0.0
AusNet	NRN	Narre Warren	0.92	0.00	0.92	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	OFR	Officer	0.92	0.00	0.92	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	PHI	Phillip Island	2.34	0.00	0.00	2.34	0.0	0.0	0.0	0.0	0.0
AusNet	PHM	Pakenham	0.92	0.00	0.92	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	RUBA	Rubicon 'A'	0.91	0.00	0.00	0.91	0.0	0.0	0.0	0.0	0.0
AusNet	RWN	Ringwood North	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	SLE	Sale	2.75	0.00	0.41	2.34	0.0	0.0	0.0	0.0	0.0
AusNet	SMG	South Morang	0.91	0.00	0.00	0.91	0.0	0.0	0.0	0.0	0.0
AusNet	SMR	Seymour	0.91	0.00	0.00	0.91	0.0	0.0	0.0	0.0	0.0

			$/kW, 2017				DG MW, 2017	$1000/y, 2017			
DNSP	ZSS	ZSS Name	Total	ZSS	Sub-trans	TS		Total	ZSS	Sub-trans	TS
AusNet	TGN	Traralgon	2.75	0.00	0.41	2.34	0.0	0.0	0.0	0.0	0.0
AusNet	TT	Thomastown	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
AusNet	WGI	Wonthaggi	2.34	0.00	0.00	2.34	0.0	0.0	0.0	0.0	0.0
AusNet	WGL	Warragul	2.36	0.00	0.01	2.34	0.0	0.0	0.0	0.0	0.0
AusNet	WN	Wangaratta	0.27	0.27	0.00	0.00	2.3	0.6	0.6	0.0	0.0
AusNet	WO	Wodonga	33.95	0.00	0.45	33.50	2.0	67.9	0.0	0.9	67.0
AusNet	WT	Watsonia	0.00	0.00	0.00	0.00	1.0	0.0	0.0	0.0	0.0
AusNet	WYK	Woori Yallock	0.00	0.00	0.00	0.00	0.9	0.0	0.0	0.0	0.0
		Average	**4.90**	**1.61**	**0.04**	**3.25**					
		Total					**124.3**	**608.7**	**200.0**	**5.0**	**403.8**

Table 16 Results for incremental (additional) PV

			$/kW, 2017			
DNSP	ZSS	ZSS Name	Total	ZSS	Sub-trans	TS
Powercor	AC	Altona Chemicals	0.00	0.00	0.00	0.00
Powercor	AL	Altona	0.00	0.00	0.00	0.00
Powercor	ART	Ararat	0.00	0.00	0.00	0.00
Powercor	BAN	Ballarat North	0.00	0.00	0.00	0.00
Powercor	BAS	Ballarat South	0.02	0.00	0.02	0.00
Powercor	BBD	Boundary Bend	0.30	0.00	0.00	0.30
Powercor	BGO	Bendigo	0.11	0.05	0.00	0.06
Powercor	BMH	Bacchus Marsh	0.00	0.00	0.00	0.00
Powercor	CDN	Camperdown	0.78	0.00	0.00	0.78
Powercor	CHA	Cohuna	0.00	0.00	0.00	0.00
Powercor	CHM	Charam	0.00	0.00	0.00	0.00
Powercor	CLC	Colac	0.00	0.00	0.00	0.00
Powercor	CME	Cobram East	0.00	0.00	0.00	0.00
Powercor	CMN	Castlemaine	0.06	0.00	0.00	0.06
Powercor	COB	Cobden	0.78	0.00	0.00	0.78
Powercor	CRO	Corio	0.00	0.00	0.00	0.00
Powercor	CTN	Charlton	0.06	0.00	0.00	0.06
Powercor	DDL	Drysdale	0.36	0.25	0.11	0.00
Powercor	DLF	Docklands	0.00	0.00	0.00	0.00

DNSP	ZSS	ZSS Name	$/kW, 2017			
			Total	ZSS	Sub-trans	TS
Powercor	ECA	Echuca	13.48	13.48	0.00	0.00
Powercor	EHK	Eaglehawk	0.09	0.03	0.00	0.06
Powercor	FNS	Ford North Shore	0.00	0.00	0.00	0.00
Powercor	GB	Geelong B	0.00	0.00	0.00	0.00
Powercor	GCY	Geelong City	0.05	0.05	0.00	0.00
Powercor	GL	Geelong	0.03	0.03	0.00	0.00
Powercor	GLE	Geelong East	0.00	0.00	0.00	0.00
Powercor	GSB	Gisborne	6.90	0.00	0.00	6.90
Powercor	HSM	Horsham	0.00	0.00	0.00	0.00
Powercor	HTN	Hamilton	0.78	0.00	0.00	0.78
Powercor	KRT	Koroit	0.78	0.00	0.00	0.78
Powercor	KYM	Kyabram	0.00	0.00	0.00	0.00
Powercor	LV	Laverton	14.44	13.67	0.00	0.78
Powercor	LVN 11	Laverton North 11	0.78	0.00	0.00	0.78
Powercor	LVN 22	Laverton North 22	0.78	0.00	0.00	0.78
Powercor	MBN	Merbein	0.30	0.00	0.00	0.30
Powercor	MDA	Mildura	0.36	0.06	0.00	0.30
Powercor	MLN	Melton	6.90	0.00	0.00	6.90
Powercor	MNA	Mooroopna	0.76	0.76	0.00	0.00
Powercor	MRO	Maryborough	0.47	0.23	0.19	0.06
Powercor	NHL	Nhill	0.01	0.01	0.00	0.00
Powercor	NKA	Numurkah	0.01	0.01	0.00	0.00
Powercor	OYN	Ouyen	0.00	0.00	0.00	0.00
Powercor	PLD	Portland	0.78	0.00	0.00	0.78
Powercor	RVL	Robinvale	0.30	0.00	0.00	0.30
Powercor	SA	St Albans	9.33	2.43	0.00	6.90
Powercor	SHL	Swan Hill	0.18	0.18	0.00	0.00
Powercor	SHN	Shepparton North	0.36	0.36	0.00	0.00
Powercor	SHP	Stanhope	0.00	0.00	0.00	0.00
Powercor	SSE	Sunshine East	6.96	0.06	0.00	6.90
Powercor	STL	Stawell	0.04	0.04	0.00	0.00
Powercor	STN	Shepparton	0.00	0.00	0.00	0.00
Powercor	SU	Sunshine	8.45	1.54	0.00	6.90
Powercor	TRG	Terang	0.78	0.00	0.00	0.78
Powercor	WBE	Werribee	1.65	0.87	0.00	0.78
Powercor	WBL	Warrnambool	0.78	0.00	0.00	0.78

			$/kW, 2017			
DNSP	ZSS	ZSS Name	Total	ZSS	Sub-trans	TS
Powercor	WIN	Winchelsea	0.00	0.00	0.00	0.00
Powercor	WMN	Wemen	4.11	4.11	0.00	0.00
Powercor	WND	Woodend	6.90	0.00	0.00	6.90
Powercor	WPD	Waurn Ponds	0.16	0.16	0.00	0.00
CitiPower	AP	Albert Park	0.00	0.00	0.00	0.00
CitiPower	AR	Armadale	1.23	0.00	0.00	1.23
CitiPower	B	Collingwood	1.23	0.00	0.00	1.23
CitiPower	BC	Balaclava	1.23	0.00	0.00	1.23
CitiPower	BK	Brunswick	0.00	0.00	0.00	0.00
CitiPower	BQ	Bouverie Queensberry	1.23	0.00	0.00	1.23
CitiPower	BS/BQ	Bouverie St/Bouverie Queensberry	1.23	0.00	0.00	1.23
CitiPower	C	Brunswick	0.00	0.00	0.00	0.00
CitiPower	CL	Camberwell	1.23	0.00	0.00	1.23
CitiPower	CW	Collingwood	3.34	2.11	0.00	1.23
CitiPower	DA	Dock Area	0.00	0.00	0.00	0.00
CitiPower	E	Fishermans Bend also	0.00	0.00	0.00	0.00
CitiPower	F	Fitzroy	0.00	0.00	0.00	0.00
CitiPower	FB	Fishermans Bend	0.00	0.00	0.00	0.00
CitiPower	FR	Flinders/Ramsden	1.50	0.27	0.00	1.23
CitiPower	J	Spencer Street	0.00	0.00	0.00	0.00
CitiPower	JA	Little Bourke Street	0.00	0.00	0.00	0.00
CitiPower	L	Deepdene	0.00	0.00	0.00	0.00
CitiPower	LQ	Little Queen	0.00	0.00	0.00	0.00
CitiPower	LS	Laurens Street	0.00	0.00	0.00	0.00
CitiPower	MG	Montague	0.00	0.00	0.00	0.00
CitiPower	MP	McIllwraith Place	1.23	0.00	0.00	1.23
CitiPower	NC	Northcote	0.04	0.04	0.00	0.00
CitiPower	NR	Nth Richmond	1.23	0.00	0.00	1.23
CitiPower	PM	Port Melbourne	0.00	0.00	0.00	0.00
CitiPower	PR	Prahran	1.23	0.00	0.00	1.23
CitiPower	Q	Kew	0.09	0.09	0.00	0.00
CitiPower	R	Richmond	4.07	2.84	0.00	1.23
CitiPower	RD	Riversdale	0.06	0.06	0.00	0.00
CitiPower	RP	Russell Place	1.23	0.00	0.00	1.23

DNSP	ZSS	ZSS Name	$/kW, 2017			
			Total	ZSS	Sub-trans	TS
CitiPower	SB	Southbank	0.00	0.00	0.00	0.00
CitiPower	SK	St Kilda	1.24	0.02	0.00	1.23
CitiPower	SO	South Melbourne	0.00	0.00	0.00	0.00
CitiPower	TK	Toorak	1.23	0.00	0.00	1.23
CitiPower	TP	Tavistock Place	0.00	0.00	0.00	0.00
CitiPower	VM	Victoria Market	0.00	0.00	0.00	0.00
CitiPower	WA	Celestial Avenue	0.05	0.05	0.00	0.00
CitiPower	WB	West Brunswick	0.09	0.09	0.00	0.00
CitiPower	WG	Westgate	0.00	0.00	0.00	0.00
UE	BH	Box Hill	0.00	0.00	0.00	0.00
UE	BR	Beaumaris	0.00	0.00	0.00	0.00
UE	BT	Bentleigh	0.00	0.00	0.00	0.00
UE	BU	Bulleen	0.00	0.00	0.00	0.00
UE	BW	Burwood	0.00	0.00	0.00	0.00
UE	CDA	Clarinda	0.00	0.00	0.00	0.00
UE	CFD	Caulfield	0.24	0.24	0.00	0.00
UE	CM	Cheltenham	0.00	0.00	0.00	0.00
UE	CRM	Carrum	0.00	0.00	0.00	0.00
UE	DC	Doncaster	0.01	0.01	0.00	0.00
UE	DMA	Dromana	0.04	0.00	0.04	0.00
UE	DN	Dandenong	0.00	0.00	0.00	0.00
UE	DSH	Dandenong South	0.00	0.00	0.00	0.00
UE	DVY	Dandenong Valley	0.00	0.00	0.00	0.00
UE	EB	East Burwood	0.00	0.00	0.00	0.00
UE	EL	Elsternwick	0.00	0.00	0.00	0.00
UE	EM	East Malvern	0.00	0.00	0.00	0.00
UE	EW	Elwood	1.23	0.00	0.00	1.23
UE	FSH	Frankston South	0.00	0.00	0.00	0.00
UE	FTN	Frankston	0.00	0.00	0.00	0.00
UE	GW	Glen Waverley	0.00	0.00	0.00	0.00
UE	HGS	Hastings	0.00	0.00	0.00	0.00
UE	HT	Heatherton	0.00	0.00	0.00	0.00
UE	K	Gardiner	1.23	0.00	0.00	1.23
UE	KBH	Keysborough	0.00	0.00	0.00	0.00
UE	LD	Lyndale	0.00	0.00	0.00	0.00
UE	LWN	Langwarrin	0.00	0.00	0.00	0.00
UE	M	Mentone	0.00	0.00	0.00	0.00
UE	MC	Mordialloc	0.00	0.00	0.00	0.00

			$/kW, 2017			
DNSP	ZSS	ZSS Name	Total	ZSS	Sub-trans	TS
UE	MGE	Mulgrave	0.00	0.00	0.00	0.00
UE	MR	Moorabbin	0.00	0.00	0.00	0.00
UE	MTN	Mornington	0.00	0.00	0.00	0.00
UE	NB	North Brighton	0.00	0.00	0.00	0.00
UE	NO	Notting Hill	0.01	0.01	0.00	0.00
UE	NP	Noble Park	0.00	0.00	0.00	0.00
UE	NW	Nunawading	0.00	0.00	0.00	0.00
UE	OAK	Oakleigh	0.00	0.00	0.00	0.00
UE	OE	Oakleigh East	0.00	0.00	0.00	0.00
UE	OR	Ormond	0.00	0.00	0.00	0.00
UE	RBD	Rosebud	0.05	0.00	0.05	0.00
UE	SH	Surrey Hills	0.00	0.00	0.00	0.00
UE	SR	Sandringham	0.00	0.00	0.00	0.00
UE	SS	Springvale South	0.00	0.00	0.00	0.00
UE	STO	Sorrento	0.00	0.00	0.00	0.00
UE	SV/SVW	Springvale/Springvale West	0.00	0.00	0.00	0.00
UE	WD	West Doncaster	0.00	0.00	0.00	0.00
Jemena	AW	Airport West	6.90	0.00	0.00	6.90
Jemena	BY	Braybrook	6.90	0.00	0.00	6.90
Jemena	BD	Broadmeadows	0.00	0.00	0.00	0.00
Jemena	BMS	Broadmeadows South	0.00	0.00	0.00	0.00
Jemena	CN	Coburg North	0.00	0.00	0.00	0.00
Jemena	CS	Coburg South	0.02	0.02	0.00	0.00
Jemena	COO	Coolaroo	0.00	0.00	0.00	0.00
Jemena	EP-A	East Preston Switch House A	0.00	0.00	0.00	0.00
Jemena	EP-B	East Preston Switch House B	0.00	0.00	0.00	0.00
Jemena	EPN	East Preston (66/22 kV)	0.00	0.00	0.00	0.00
Jemena	ES	Essendon	6.90	0.00	0.00	6.90
Jemena	FF	Fairfield	0.00	0.00	0.00	0.00
Jemena	FT	Flemington	0.00	0.00	0.00	0.00
Jemena	FE	Footscray East	0.00	0.00	0.00	0.00
Jemena	FW	Footscray West	0.00	0.00	0.00	0.00
Jemena	HB	Heidelberg	0.00	0.00	0.00	0.00
Jemena	NT	Newport	0.00	0.00	0.00	0.00

			$/kW, 2017			
DNSP	ZSS	ZSS Name	Total	ZSS	Sub-trans	TS
Jemena	NS	North Essendon	0.00	0.00	0.00	0.00
Jemena	NH	North Heidelberg	0.00	0.00	0.00	0.00
Jemena	PV	Pascoe Vale	6.90	0.00	0.00	6.90
Jemena	P	Preston	0.00	0.00	0.00	0.00
Jemena	ST	Somerton	0.13	0.00	0.00	0.13
Jemena	SBY	Sunbury	6.90	0.00	0.00	6.90
Jemena	SHM	Sydenham	6.91	0.01	0.00	6.90
Jemena	TH	Tottenham	0.00	0.00	0.00	0.00
Jemena	TMA	Tullamarine	6.90	0.00	0.00	6.90
Jemena	YVE	Yarraville	0.00	0.00	0.00	0.00
AusNet	BDL	Bairnsdale	0.49	0.00	0.03	0.45
AusNet	BGE	Belgrave	0.00	0.00	0.00	0.00
AusNet	BN	Benalla	0.42	0.42	0.00	0.00
AusNet	BRA	Boronia	0.00	0.00	0.00	0.00
AusNet	BRT	Bright	0.00	0.00	0.00	0.00
AusNet	BWA	Barnawatha	25.82	0.00	17.51	8.31
AusNet	BWN	Berwick North	0.17	0.00	0.17	0.00
AusNet	BWR	Bayswater	0.00	0.00	0.00	0.00
AusNet	CF	Clover Flat	0.00	0.00	0.00	0.00
AusNet	CLN	Clyde North	5.10	4.93	0.17	0.00
AusNet	CNR	Cann River	0.46	0.00	0.00	0.45
AusNet	CPK	Chirnside Park	0.00	0.00	0.00	0.00
AusNet	CRE	Cranbourne	0.00	0.00	0.00	0.00
AusNet	CYN	Croydon	0.00	0.00	0.00	0.00
AusNet	DRN	Doreen	1.24	1.11	0.00	0.13
AusNet	ELM	Eltham	0.00	0.00	0.00	0.00
AusNet	EPG	Epping	0.13	0.00	0.00	0.13
AusNet	FGY	Ferntree Gully	0.00	0.00	0.00	0.00
AusNet	FTR	Foster	0.45	0.00	0.00	0.45
AusNet	HPK	Hampton Park	0.00	0.00	0.00	0.00
AusNet	KLK	Kinglake	0.29	0.00	0.16	0.13
AusNet	KLO	Kalkallo	0.13	0.00	0.00	0.13
AusNet	KMS	Kilmore South	0.29	0.00	0.16	0.13
AusNet	LDL	Lilydale	0.00	0.00	0.00	0.00
AusNet	LGA	Leongatha	0.45	0.00	0.00	0.45
AusNet	LLG	Lang Lang	0.17	0.00	0.17	0.00
AusNet	LYD	Lysterfield	0.18	0.01	0.17	0.00
AusNet	MBY	Mt Beauty	0.00	0.00	0.00	0.00

DNSP	ZSS	ZSS Name	$/kW, 2017			
			Total	ZSS	Sub-trans	TS
AusNet	MDI	Murrindindi	0.29	0.00	0.16	0.13
AusNet	MFA	Maffra	0.49	0.00	0.03	0.45
AusNet	MJG	Merrijig	1.78	0.00	1.78	0.00
AusNet	MOE	Moe	0.45	0.00	0.00	0.45
AusNet	MSD	Mansfield	0.00	0.00	0.00	0.00
AusNet	MWT	Morwell	0.45	0.00	0.00	0.45
AusNet	MYT	Myrtleford	0.00	0.00	0.00	0.00
AusNet	NLA	Newmerella	0.45	0.00	0.00	0.45
AusNet	NRN	Narre Warren	0.17	0.00	0.17	0.00
AusNet	OFR	Officer	0.17	0.00	0.17	0.00
AusNet	PHI	Phillip Island	2.30	0.00	1.85	0.45
AusNet	PHM	Pakenham	0.17	0.00	0.17	0.00
AusNet	RUBA	Rubicon 'A'	0.29	0.00	0.16	0.13
AusNet	RWN	Ringwood North	0.00	0.00	0.00	0.00
AusNet	SLE	Sale	0.49	0.00	0.03	0.45
AusNet	SMG	South Morang	0.13	0.00	0.00	0.13
AusNet	SMR	Seymour	0.29	0.00	0.16	0.13
AusNet	TGN	Traralgon	0.49	0.00	0.03	0.45
AusNet	TT	Thomastown	2.36	2.36	0.00	0.00
AusNet	WGI	Wonthaggi	0.92	0.00	0.47	0.45
AusNet	WGL	Warragul	0.56	0.11	0.00	0.45
AusNet	WN	Wangaratta	0.03	0.03	0.00	0.00
AusNet	WO	Wodonga	8.39	0.00	0.08	8.31
AusNet	WT	Watsonia	0.00	0.00	0.00	0.00
AusNet	WYK	Woori Yallock	0.00	0.00	0.00	0.00
		Average	**0.99**	**0.24**	**0.11**	**0.64**

Table 17 Results for incremental (additional) dispatchable DG

DNSP	ZSS	ZSS Name	$/kW, 2017			
			Total	ZSS	Sub-trans	TS
Powercor	AC	Altona Chemicals	0.00	0.00	0.00	0.00
Powercor	AL	Altona	0.00	0.00	0.00	0.00
Powercor	ART	Ararat	0.04	0.00	0.00	0.04
Powercor	BAN	Ballarat North	0.04	0.00	0.00	0.04
Powercor	BAS	Ballarat South	0.75	0.00	0.71	0.04
Powercor	BBD	Boundary Bend	1.11	0.00	0.00	1.11

DNSP	ZSS	ZSS Name	$/kW, 2017			
			Total	ZSS	Sub-trans	TS
Powercor	BGO	Bendigo	0.82	0.20	0.00	0.63
Powercor	BMH	Bacchus Marsh	0.00	0.00	0.00	0.00
Powercor	CDN	Camperdown	53.50	0.00	0.00	53.50
Powercor	CHA	Cohuna	0.00	0.00	0.00	0.00
Powercor	CHM	Charam	0.00	0.00	0.00	0.00
Powercor	CLC	Colac	0.00	0.00	0.00	0.00
Powercor	CME	Cobram East	0.00	0.00	0.00	0.00
Powercor	CMN	Castlemaine	0.93	0.00	0.30	0.63
Powercor	COB	Cobden	53.50	0.00	0.00	53.50
Powercor	CRO	Corio	0.00	0.00	0.00	0.00
Powercor	CTN	Charlton	0.63	0.00	0.00	0.63
Powercor	DDL	Drysdale	1.88	1.11	0.77	0.00
Powercor	DLF	Docklands	0.00	0.00	0.00	0.00
Powercor	ECA	Echuca	43.77	43.77	0.00	0.00
Powercor	EHK	Eaglehawk	0.95	0.32	0.01	0.63
Powercor	FNS	Ford North Shore	0.00	0.00	0.00	0.00
Powercor	GB	Geelong B	0.00	0.00	0.00	0.00
Powercor	GCY	Geelong City	0.17	0.17	0.00	0.00
Powercor	GL	Geelong	0.20	0.20	0.00	0.00
Powercor	GLE	Geelong East	0.00	0.00	0.00	0.00
Powercor	GSB	Gisborne	37.41	0.00	0.00	37.41
Powercor	HSM	Horsham	0.00	0.00	0.00	0.00
Powercor	HTN	Hamilton	53.50	0.00	0.00	53.50
Powercor	KRT	Koroit	53.50	0.00	0.00	53.50
Powercor	KYM	Kyabram	0.00	0.00	0.00	0.00
Powercor	LV	Laverton	118.13	113.46	0.00	4.67
Powercor	LVN 11	Laverton North 11	4.67	0.00	0.00	4.67
Powercor	LVN 22	Laverton North 22	4.67	0.00	0.00	4.67
Powercor	MBN	Merbein	1.11	0.00	0.00	1.11
Powercor	MDA	Mildura	1.30	0.19	0.00	1.11
Powercor	MLN	Melton	37.41	0.00	0.00	37.41
Powercor	MNA	Mooroopna	3.78	3.76	0.01	0.00
Powercor	MRO	Maryborough	6.34	2.25	3.47	0.63
Powercor	NHL	Nhill	0.19	0.19	0.00	0.00
Powercor	NKA	Numurkah	0.31	0.31	0.00	0.00
Powercor	OYN	Ouyen	0.00	0.00	0.00	0.00

DNSP	ZSS	ZSS Name	$/kW, 2017			
			Total	ZSS	Sub-trans	TS
Powercor	PLD	Portland	53.50	0.00	0.00	53.50
Powercor	RVL	Robinvale	1.11	0.00	0.00	1.11
Powercor	SA	St Albans	68.95	31.54	0.00	37.41
Powercor	SHL	Swan Hill	0.99	0.99	0.00	0.00
Powercor	SHN	Shepparton North	1.15	1.15	0.00	0.00
Powercor	SHP	Stanhope	0.00	0.00	0.00	0.00
Powercor	SSE	Sunshine East	37.59	0.19	0.00	37.41
Powercor	STL	Stawell	0.24	0.24	0.00	0.00
Powercor	STN	Shepparton	0.01	0.00	0.01	0.00
Powercor	SU	Sunshine	49.87	12.46	0.00	37.41
Powercor	TRG	Terang	53.50	0.00	0.00	53.50
Powercor	WBE	Werribee	23.83	19.16	0.00	4.67
Powercor	WBL	Warrnambool	53.50	0.00	0.00	53.50
Powercor	WIN	Winchelsea	0.00	0.00	0.00	0.00
Powercor	WMN	Wemen	22.80	22.80	0.00	0.00
Powercor	WND	Woodend	37.41	0.00	0.00	37.41
Powercor	WPD	Waurn Ponds	0.63	0.63	0.00	0.00
CitiPower	AP	Albert Park	0.00	0.00	0.00	0.00
CitiPower	AR	Armadale	3.90	0.07	0.00	3.84
CitiPower	B	Collingwood	3.84	0.00	0.00	3.84
CitiPower	BC	Balaclava	3.84	0.00	0.00	3.84
CitiPower	BK	Brunswick	0.00	0.00	0.00	0.00
CitiPower	BQ	Bouverie Queensberry	3.84	0.00	0.00	3.84
CitiPower	BS/BQ	Bouverie St/Bouverie Queensberry	3.84	0.00	0.00	3.84
CitiPower	C	Brunswick	0.00	0.00	0.00	0.00
CitiPower	CL	Camberwell	3.84	0.00	0.00	3.84
CitiPower	CW	Collingwood	12.49	8.65	0.00	3.84
CitiPower	DA	Dock Area	0.16	0.10	0.06	0.00
CitiPower	E	Fishermans Bend also	0.00	0.00	0.00	0.00
CitiPower	F	Fitzroy	0.00	0.00	0.00	0.00
CitiPower	FB	Fishermans Bend	0.00	0.00	0.00	0.00
CitiPower	FR	Flinders/Ramsden	4.77	0.93	0.00	3.84
CitiPower	J	Spencer Street	0.00	0.00	0.00	0.00
CitiPower	JA	Little Bourke Street	0.00	0.00	0.00	0.00

			$/kW, 2017			
DNSP	ZSS	ZSS Name	Total	ZSS	Sub-trans	TS
CitiPower	L	Deepdene	0.00	0.00	0.00	0.00
CitiPower	LQ	Little Queen	0.00	0.00	0.00	0.00
CitiPower	LS	Laurens Street	0.00	0.00	0.00	0.00
CitiPower	MG	Montague	0.00	0.00	0.00	0.00
CitiPower	MP	McIllwraith Place	3.84	0.00	0.00	3.84
CitiPower	NC	Northcote	2.68	2.68	0.00	0.00
CitiPower	NR	Nth Richmond	3.84	0.00	0.00	3.84
CitiPower	PM	Port Melbourne	0.00	0.00	0.00	0.00
CitiPower	PR	Prahran	3.84	0.00	0.00	3.84
CitiPower	Q	Kew	0.43	0.43	0.00	0.00
CitiPower	R	Richmond	13.43	9.59	0.00	3.84
CitiPower	RD	Riversdale	0.38	0.38	0.00	0.00
CitiPower	RP	Russell Place	3.84	0.00	0.00	3.84
CitiPower	SB	Southbank	0.00	0.00	0.00	0.00
CitiPower	SK	St Kilda	3.92	0.08	0.00	3.84
CitiPower	SO	South Melbourne	0.00	0.00	0.00	0.00
CitiPower	TK	Toorak	3.84	0.00	0.00	3.84
CitiPower	TP	Tavistock Place	0.00	0.00	0.00	0.00
CitiPower	VM	Victoria Market	0.00	0.00	0.00	0.00
CitiPower	WA	Celestial Avenue	0.11	0.11	0.00	0.00
CitiPower	WB	West Brunswick	0.32	0.32	0.00	0.00
CitiPower	WG	Westgate	0.00	0.00	0.00	0.00
UE	BH	Box Hill	0.00	0.00	0.00	0.00
UE	BR	Beaumaris	0.00	0.00	0.00	0.00
UE	BT	Bentleigh	0.00	0.00	0.00	0.00
UE	BU	Bulleen	0.00	0.00	0.00	0.00
UE	BW	Burwood	0.00	0.00	0.00	0.00
UE	CDA	Clarinda	0.00	0.00	0.00	0.00
UE	CFD	Caulfield	2.43	2.43	0.00	0.00
UE	CM	Cheltenham	0.00	0.00	0.00	0.00
UE	CRM	Carrum	0.00	0.00	0.00	0.00
UE	DC	Doncaster	0.09	0.09	0.00	0.00
UE	DMA	Dromana	0.53	0.00	0.53	0.00
UE	DN	Dandenong	0.00	0.00	0.00	0.00
UE	DSH	Dandenong South	0.00	0.00	0.00	0.00
UE	DVY	Dandenong Valley	0.00	0.00	0.00	0.00
UE	EB	East Burwood	0.00	0.00	0.00	0.00
UE	EL	Elsternwick	0.00	0.00	0.00	0.00

			$/kW, 2017			
DNSP	ZSS	ZSS Name	Total	ZSS	Sub-trans	TS
UE	EM	East Malvern	0.00	0.00	0.00	0.00
UE	EW	Elwood	3.84	0.00	0.00	3.84
UE	FSH	Frankston South	0.00	0.00	0.00	0.00
UE	FTN	Frankston	0.00	0.00	0.00	0.00
UE	GW	Glen Waverley	0.00	0.00	0.00	0.00
UE	HGS	Hastings	0.00	0.00	0.00	0.00
UE	HT	Heatherton	0.00	0.00	0.00	0.00
UE	K	Gardiner	3.85	0.00	0.01	3.84
UE	KBH	Keysborough	0.00	0.00	0.00	0.00
UE	LD	Lyndale	0.00	0.00	0.00	0.00
UE	LWN	Langwarrin	0.00	0.00	0.00	0.00
UE	M	Mentone	0.00	0.00	0.00	0.00
UE	MC	Mordialloc	0.00	0.00	0.00	0.00
UE	MGE	Mulgrave	0.00	0.00	0.00	0.00
UE	MR	Moorabbin	0.00	0.00	0.00	0.00
UE	MTN	Mornington	0.00	0.00	0.00	0.00
UE	NB	North Brighton	0.00	0.00	0.00	0.00
UE	NO	Notting Hill	0.04	0.04	0.00	0.00
UE	NP	Noble Park	0.00	0.00	0.00	0.00
UE	NW	Nunawading	0.00	0.00	0.00	0.00
UE	OAK	Oakleigh	0.00	0.00	0.00	0.00
UE	OE	Oakleigh East	0.00	0.00	0.00	0.00
UE	OR	Ormond	0.00	0.00	0.00	0.00
UE	RBD	Rosebud	0.57	0.00	0.57	0.00
UE	SH	Surrey Hills	0.00	0.00	0.00	0.00
UE	SR	Sandringham	0.00	0.00	0.00	0.00
UE	SS	Springvale South	0.00	0.00	0.00	0.00
UE	STO	Sorrento	0.00	0.00	0.00	0.00
UE	SV/SVW	Springvale/Springvale West	0.00	0.00	0.00	0.00
UE	WD	West Doncaster	0.00	0.00	0.00	0.00
Jemena	AW	Airport West	37.41	0.00	0.00	37.41
Jemena	BY	Braybrook	37.41	0.00	0.00	37.41
Jemena	BD	Broadmeadows	0.00	0.00	0.00	0.00
Jemena	BMS	Broadmeadows South	0.00	0.00	0.00	0.00
Jemena	CN	Coburg North	0.00	0.00	0.00	0.00
Jemena	CS	Coburg South	0.15	0.15	0.00	0.00

			$/kW, 2017			
DNSP	ZSS	ZSS Name	Total	ZSS	Sub-trans	TS
Jemena	COO	Coolaroo	0.00	0.00	0.00	0.00
Jemena	EP-A	East Preston Switch House A	0.00	0.00	0.00	0.00
Jemena	EP-B	East Preston Switch House B	0.00	0.00	0.00	0.00
Jemena	EPN	East Preston (66/22 kV)	0.00	0.00	0.00	0.00
Jemena	ES	Essendon	37.41	0.00	0.00	37.41
Jemena	FF	Fairfield	0.00	0.00	0.00	0.00
Jemena	FT	Flemington	0.00	0.00	0.00	0.00
Jemena	FE	Footscray East	0.00	0.00	0.00	0.00
Jemena	FW	Footscray West	0.00	0.00	0.00	0.00
Jemena	HB	Heidelberg	0.00	0.00	0.00	0.00
Jemena	NT	Newport	0.00	0.00	0.00	0.00
Jemena	NS	North Essendon	0.00	0.00	0.00	0.00
Jemena	NH	North Heidelberg	0.00	0.00	0.00	0.00
Jemena	PV	Pascoe Vale	37.41	0.00	0.00	37.41
Jemena	P	Preston	0.00	0.00	0.00	0.00
Jemena	ST	Somerton	0.91	0.00	0.00	0.91
Jemena	SBY	Sunbury	37.41	0.00	0.00	37.41
Jemena	SHM	Sydenham	37.48	0.08	0.00	37.41
Jemena	TH	Tottenham	0.00	0.00	0.00	0.00
Jemena	TMA	Tullamarine	37.41	0.00	0.00	37.41
Jemena	YVE	Yarraville	0.00	0.00	0.00	0.00
AusNet	BDL	Bairnsdale	2.33	0.00	0.34	1.99
AusNet	BGE	Belgrave	0.00	0.00	0.00	0.00
AusNet	BN	Benalla	3.13	3.13	0.00	0.00
AusNet	BRA	Boronia	0.00	0.00	0.00	0.00
AusNet	BRT	Bright	0.04	0.00	0.04	0.00
AusNet	BWA	Barnawatha	178.19	0.00	149.50	28.69
AusNet	BWN	Berwick North	0.92	0.00	0.92	0.00
AusNet	BWR	Bayswater	0.00	0.00	0.00	0.00
AusNet	CF	Clover Flat	0.00	0.00	0.00	0.00
AusNet	CLN	Clyde North	32.29	31.37	0.92	0.00
AusNet	CNR	Cann River	2.08	0.00	0.09	1.99
AusNet	CPK	Chirnside Park	0.00	0.00	0.00	0.00
AusNet	CRE	Cranbourne	0.00	0.00	0.00	0.00
AusNet	CYN	Croydon	0.00	0.00	0.00	0.00
AusNet	DRN	Doreen	20.11	19.20	0.00	0.91

			$/kW, 2017			
DNSP	ZSS	ZSS Name	Total	ZSS	Sub-trans	TS
AusNet	ELM	Eltham	0.00	0.00	0.00	0.00
AusNet	EPG	Epping	0.91	0.00	0.00	0.91
AusNet	FGY	Ferntree Gully	0.00	0.00	0.00	0.00
AusNet	FTR	Foster	1.99	0.00	0.00	1.99
AusNet	HPK	Hampton Park	0.00	0.00	0.00	0.00
AusNet	KLK	Kinglake	2.22	0.00	1.32	0.91
AusNet	KLO	Kalkallo	109.83	0.00	108.92	0.91
AusNet	KMS	Kilmore South	2.22	0.00	1.32	0.91
AusNet	LDL	Lilydale	0.00	0.00	0.00	0.00
AusNet	LGA	Leongatha	1.99	0.00	0.00	1.99
AusNet	LLG	Lang Lang	0.92	0.00	0.92	0.00
AusNet	LYD	Lysterfield	1.00	0.08	0.92	0.00
AusNet	MBY	Mt Beauty	10.55	0.00	10.55	0.00
AusNet	MDI	Murrindindi	2.22	0.00	1.32	0.91
AusNet	MFA	Maffra	2.33	0.00	0.34	1.99
AusNet	MJG	Merrijig	32.91	0.00	32.91	0.00
AusNet	MOE	Moe	1.99	0.00	0.00	1.99
AusNet	MSD	Mansfield	0.00	0.00	0.00	0.00
AusNet	MWT	Morwell	1.99	0.00	0.00	1.99
AusNet	MYT	Myrtleford	0.04	0.00	0.04	0.00
AusNet	NLA	Newmerella	1.99	0.00	0.00	1.99
AusNet	NRN	Narre Warren	0.92	0.00	0.92	0.00
AusNet	OFR	Officer	0.92	0.00	0.92	0.00
AusNet	PHI	Phillip Island	47.85	0.00	45.86	1.99
AusNet	PHM	Pakenham	0.92	0.00	0.92	0.00
AusNet	RUBA	Rubicon 'A'	2.22	0.00	1.32	0.91
AusNet	RWN	Ringwood North	0.00	0.00	0.00	0.00
AusNet	SLE	Sale	2.33	0.00	0.34	1.99
AusNet	SMG	South Morang	0.91	0.00	0.00	0.91
AusNet	SMR	Seymour	2.22	0.00	1.32	0.91
AusNet	TGN	Traralgon	2.33	0.00	0.34	1.99
AusNet	TT	Thomastown	8.03	8.03	0.00	0.00
AusNet	WGI	Wonthaggi	10.20	5.17	3.03	1.99
AusNet	WGL	Warragul	2.85	0.86	0.00	1.99
AusNet	WN	Wangaratta	0.16	0.16	0.00	0.00
AusNet	WO	Wodonga	28.92	0.00	0.24	28.69
AusNet	WT	Watsonia	0.00	0.00	0.00	0.00
AusNet	WYK	Woori Yallock	0.00	0.00	0.00	0.00

			$/kW, 2017			
DNSP	ZSS	ZSS Name	Total	ZSS	Sub-trans	TS
		Average	**7.88**	**1.56**	**1.66**	**4.66**

Appendix C. Maps showing locational benefits

C.1 Annual benefit in 2017

Figure 44 Existing PV benefit in 2017, $/year

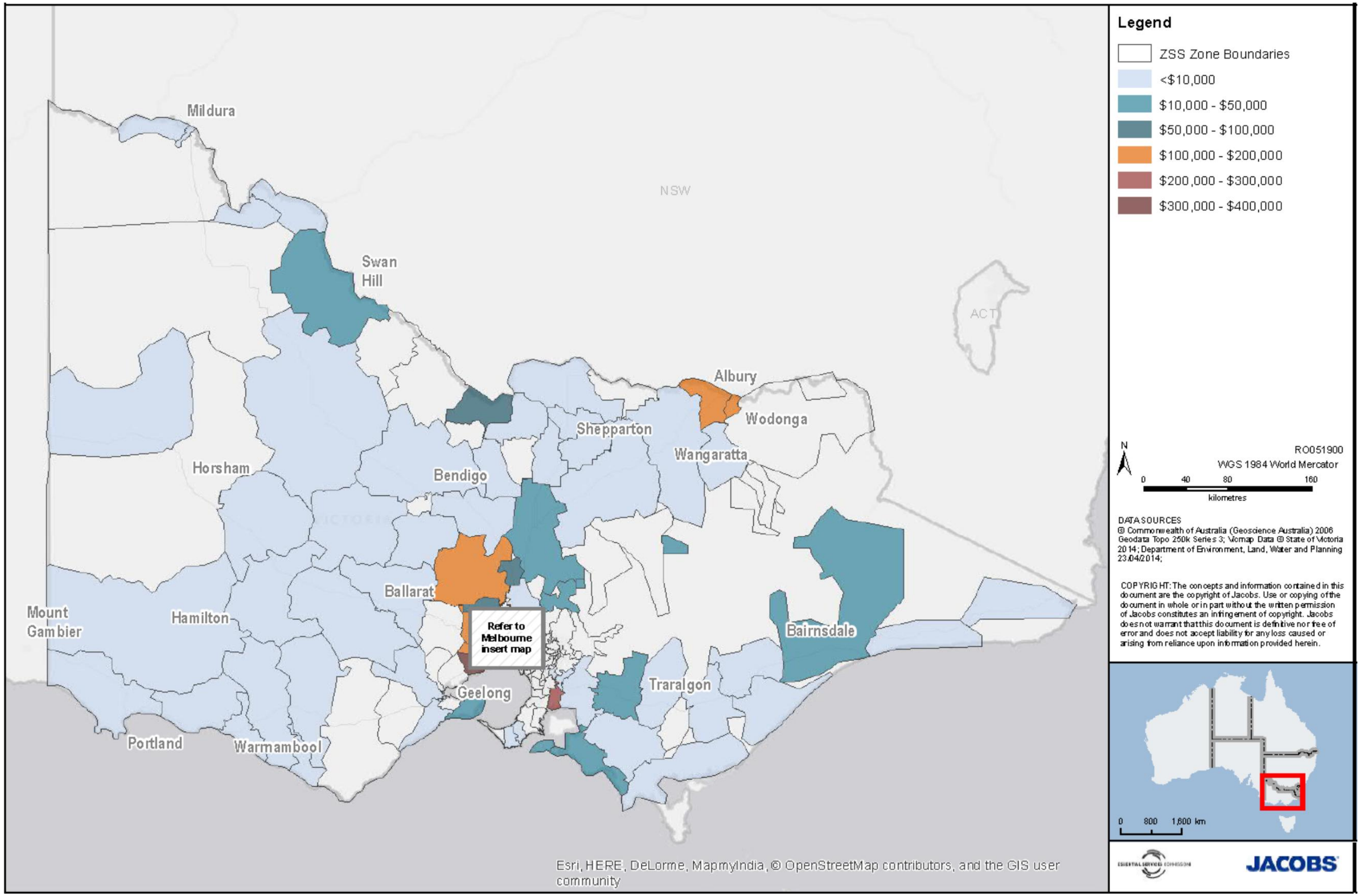


Figure 45 Existing dispatchable generation benefit in 2017, $/year

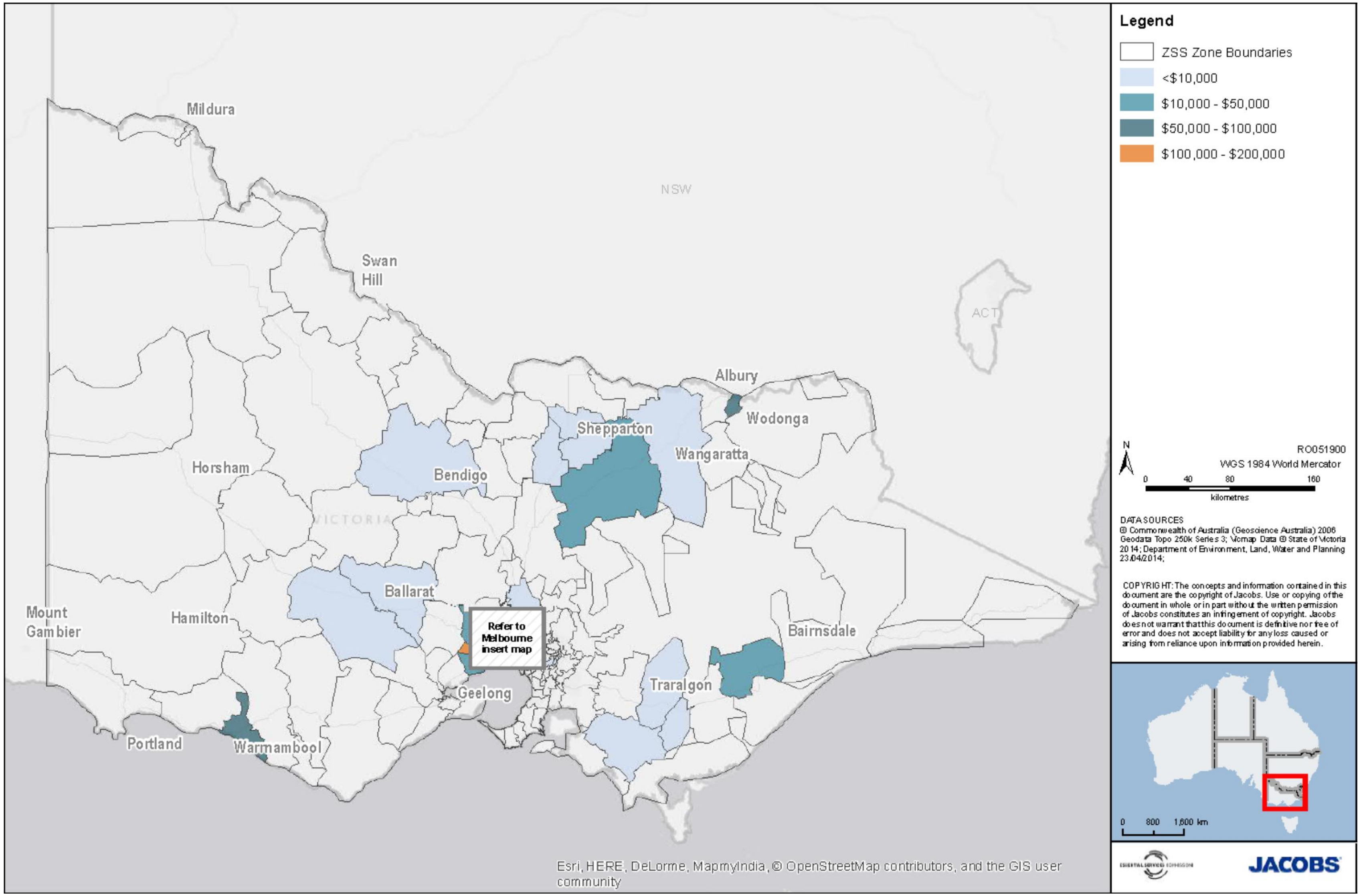


Figure 46 Existing all-DG generation benefit in 2017, $/year

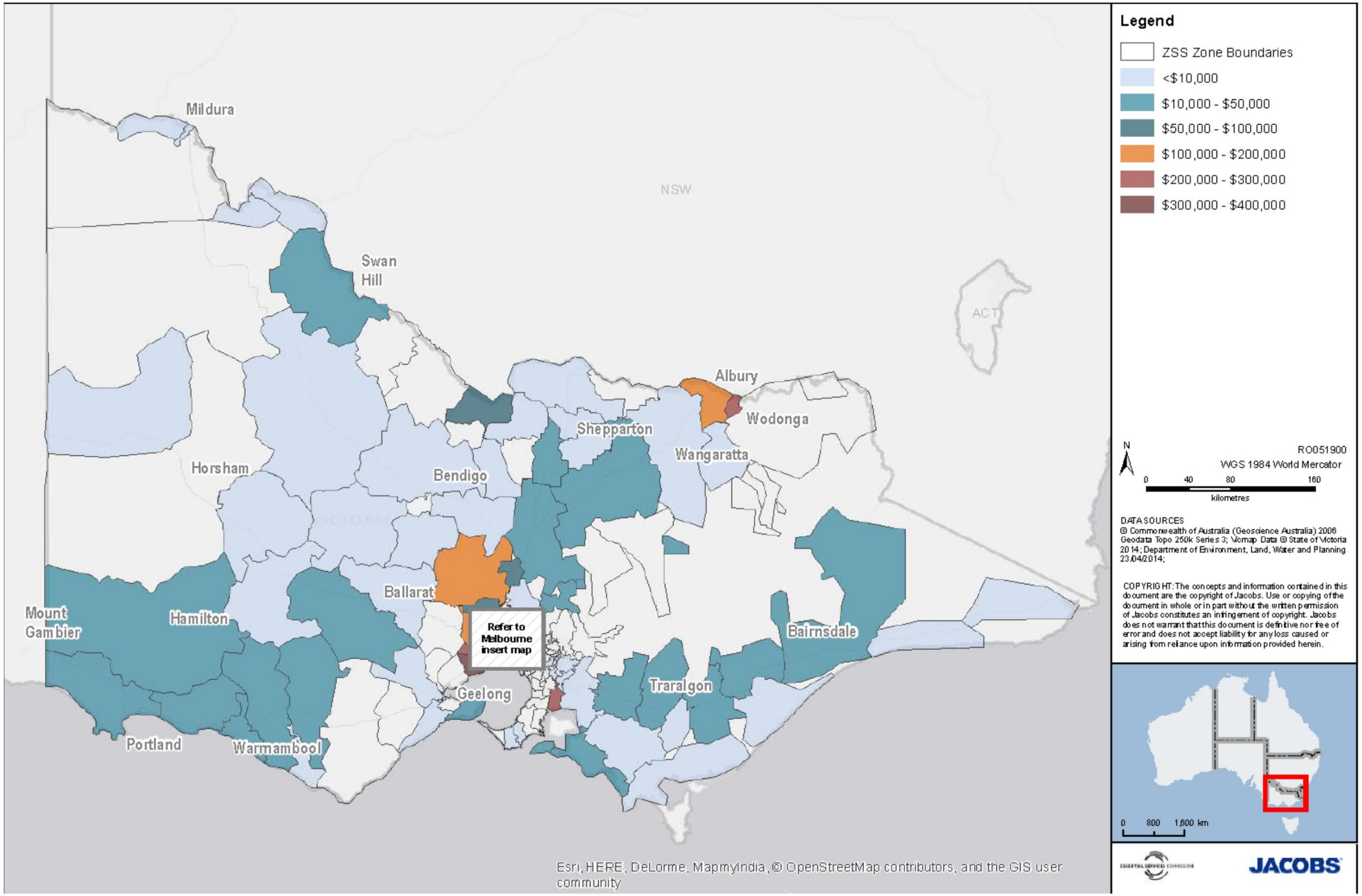


Figure 47 Existing PV benefit in 2017 in Melbourne metropolitan area, $/year

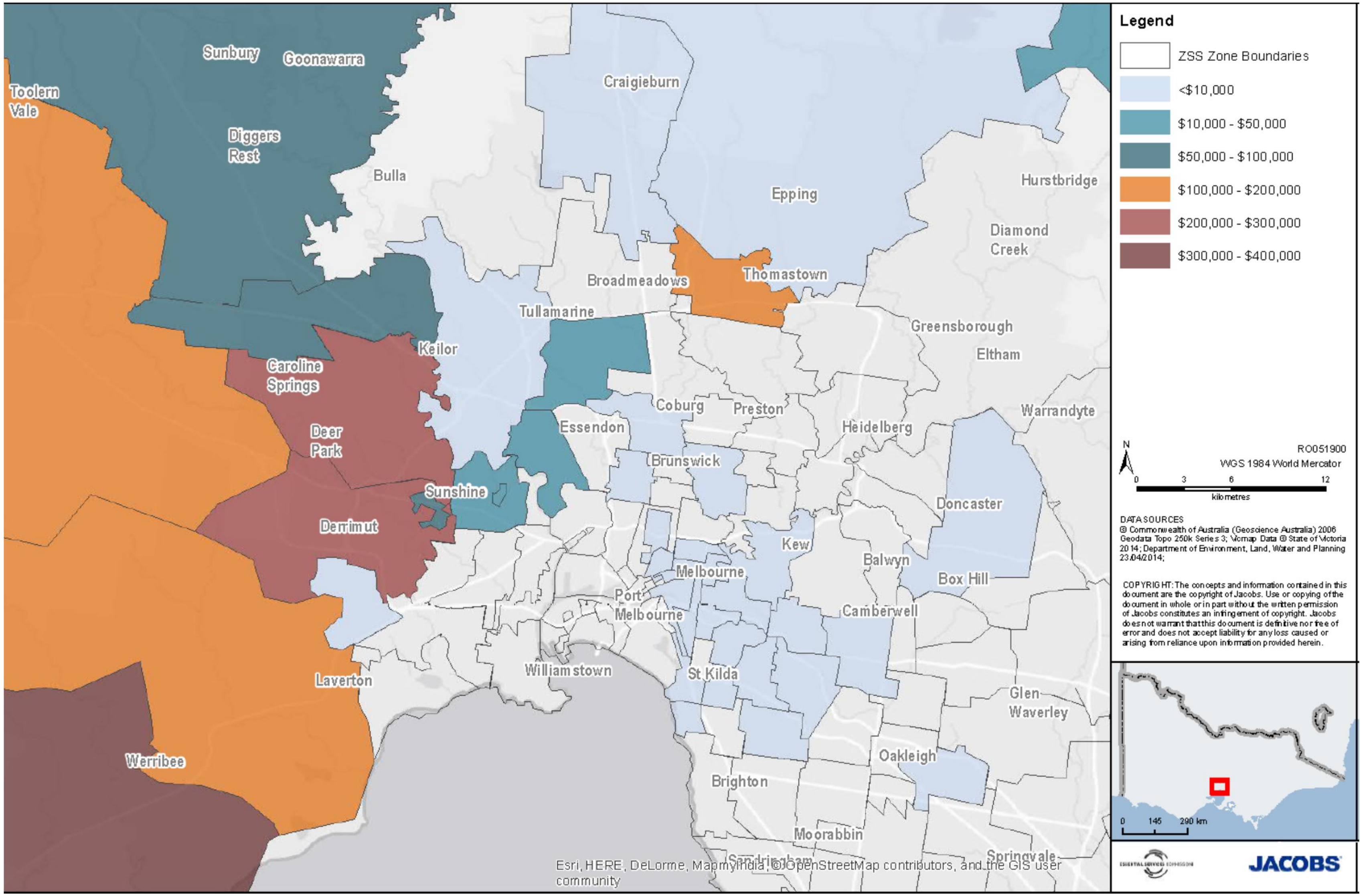


Figure 48 Existing dispatchable generation benefit in 2017 in Melbourne metropolitan area, $/year

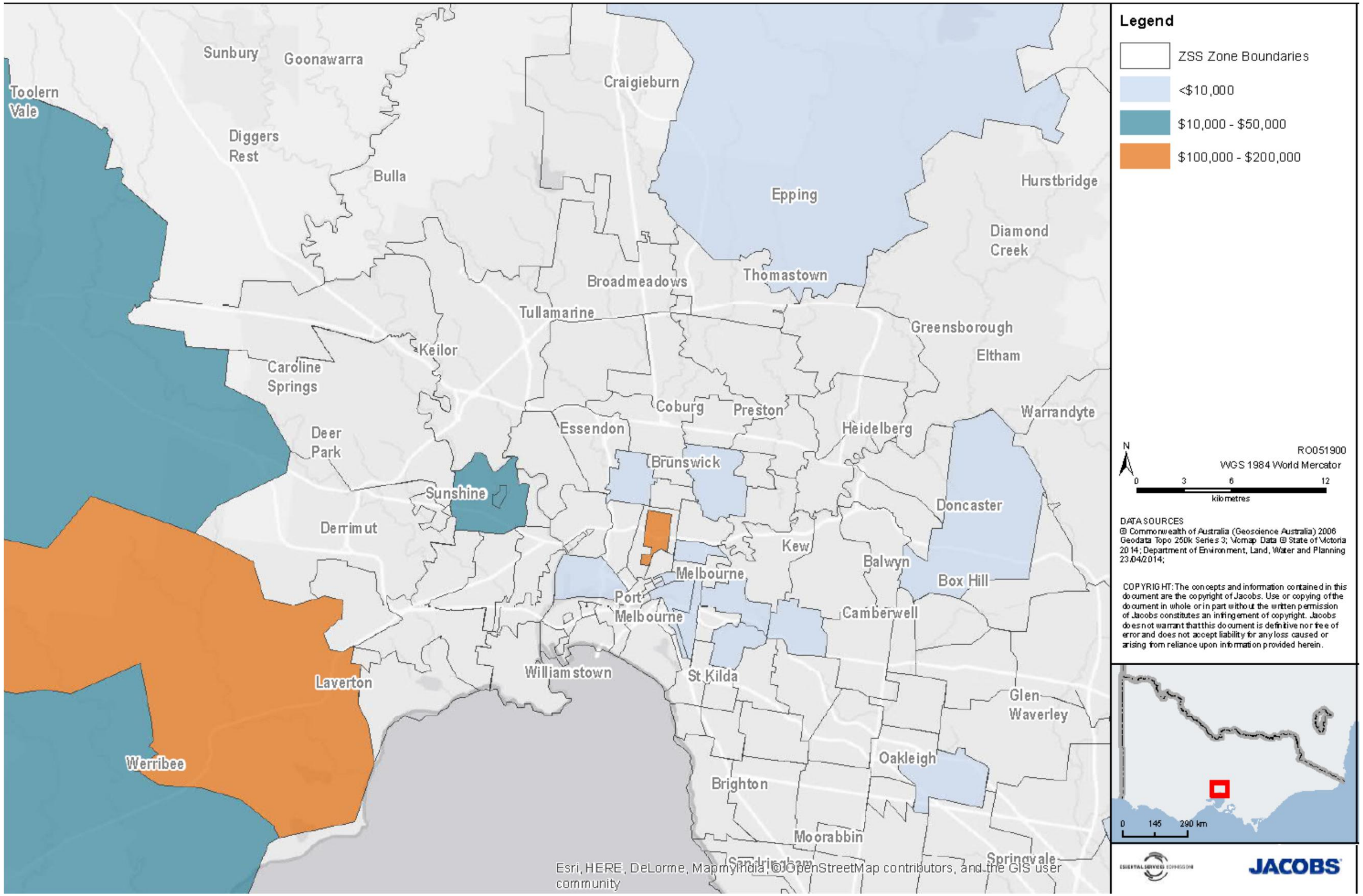
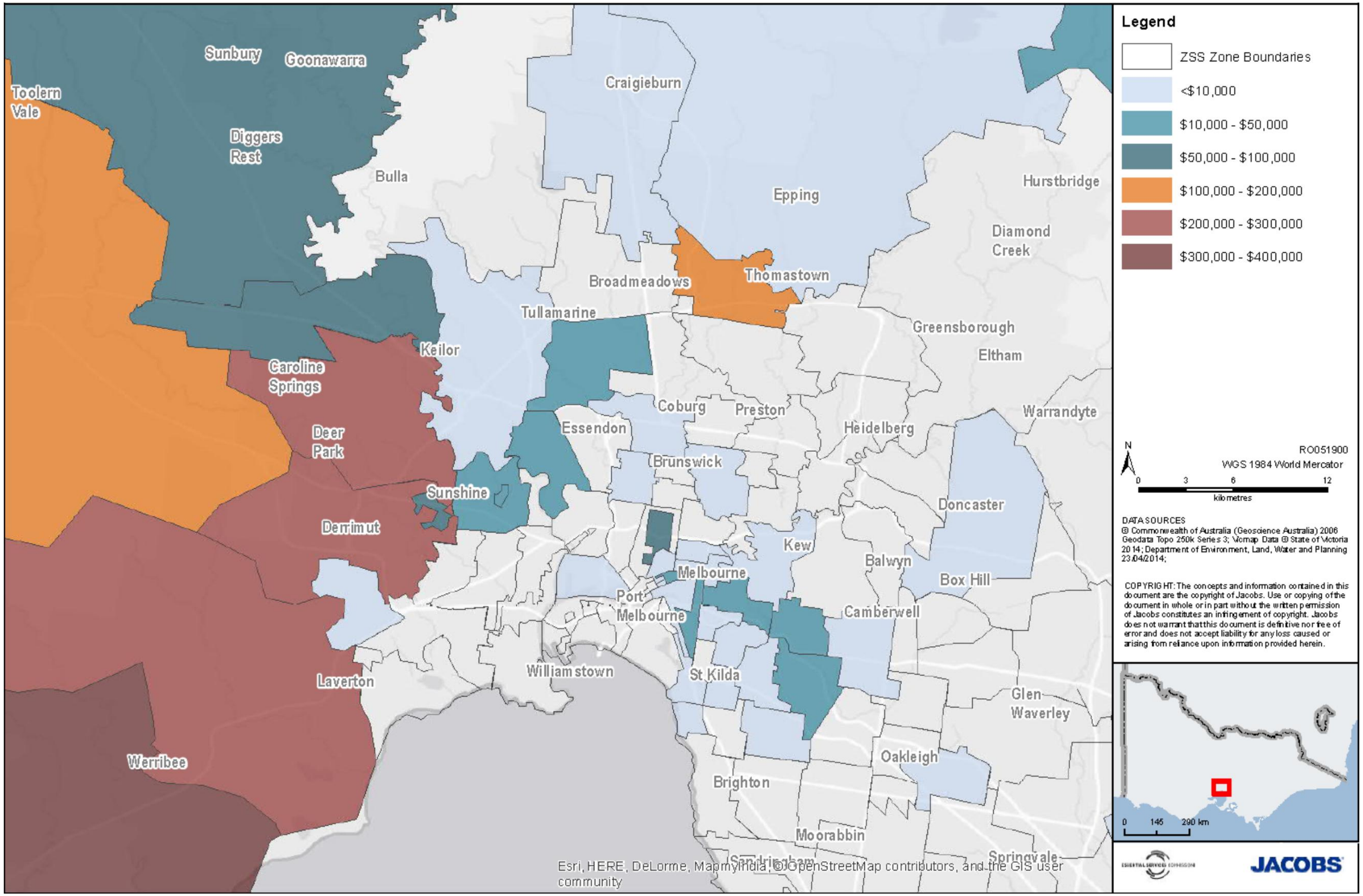


Figure 49 Existing all-DG generation benefit in 2017 in Melbourne metropolitan area, $/year



C.2 Specific annual benefit in 2017

Figure 50 Specific benefit of existing PV in 2017, $/kW/y

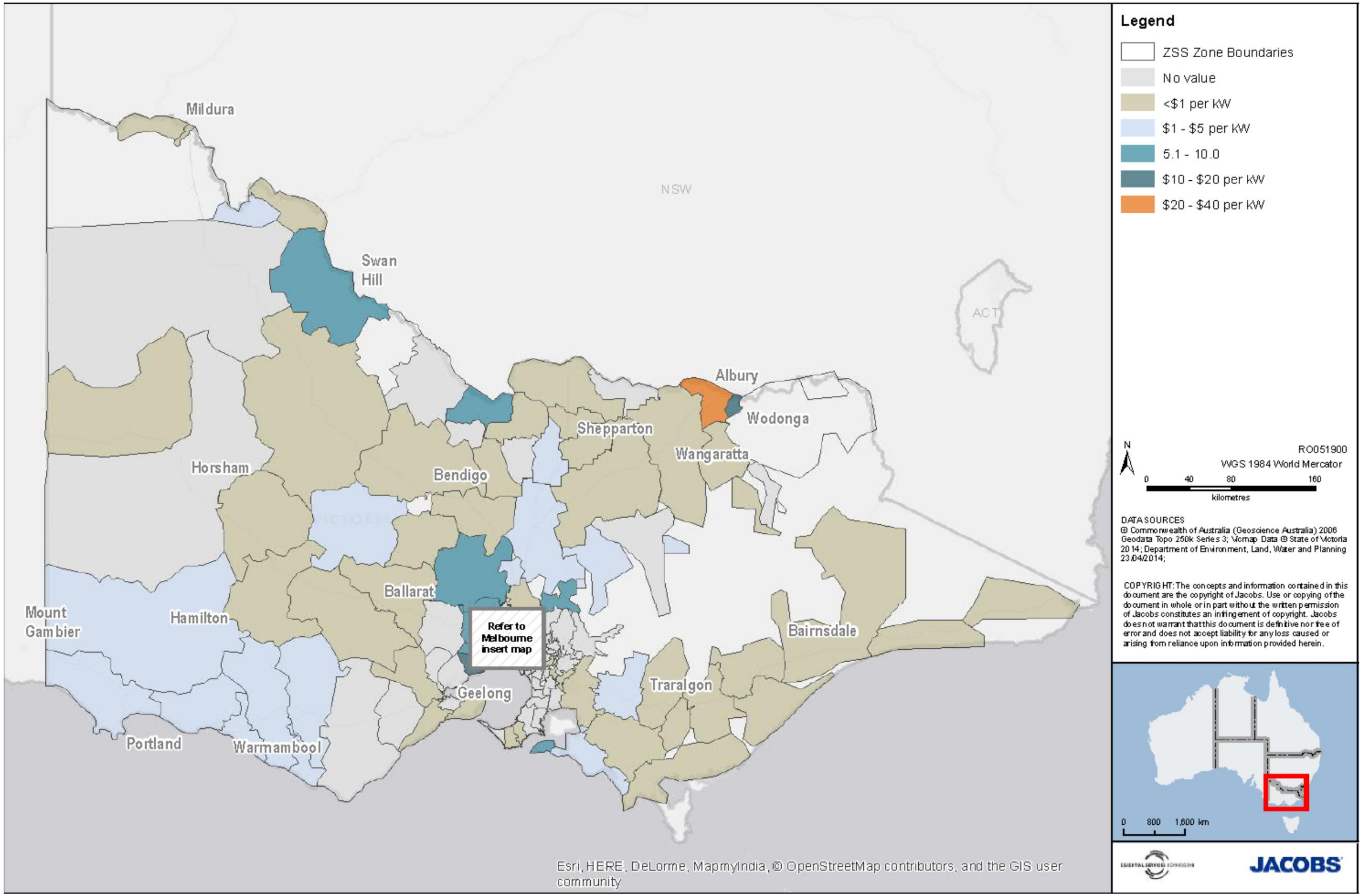


Figure 51 Specific benefit of existing dispatchable DG in 2017, $/kW/y

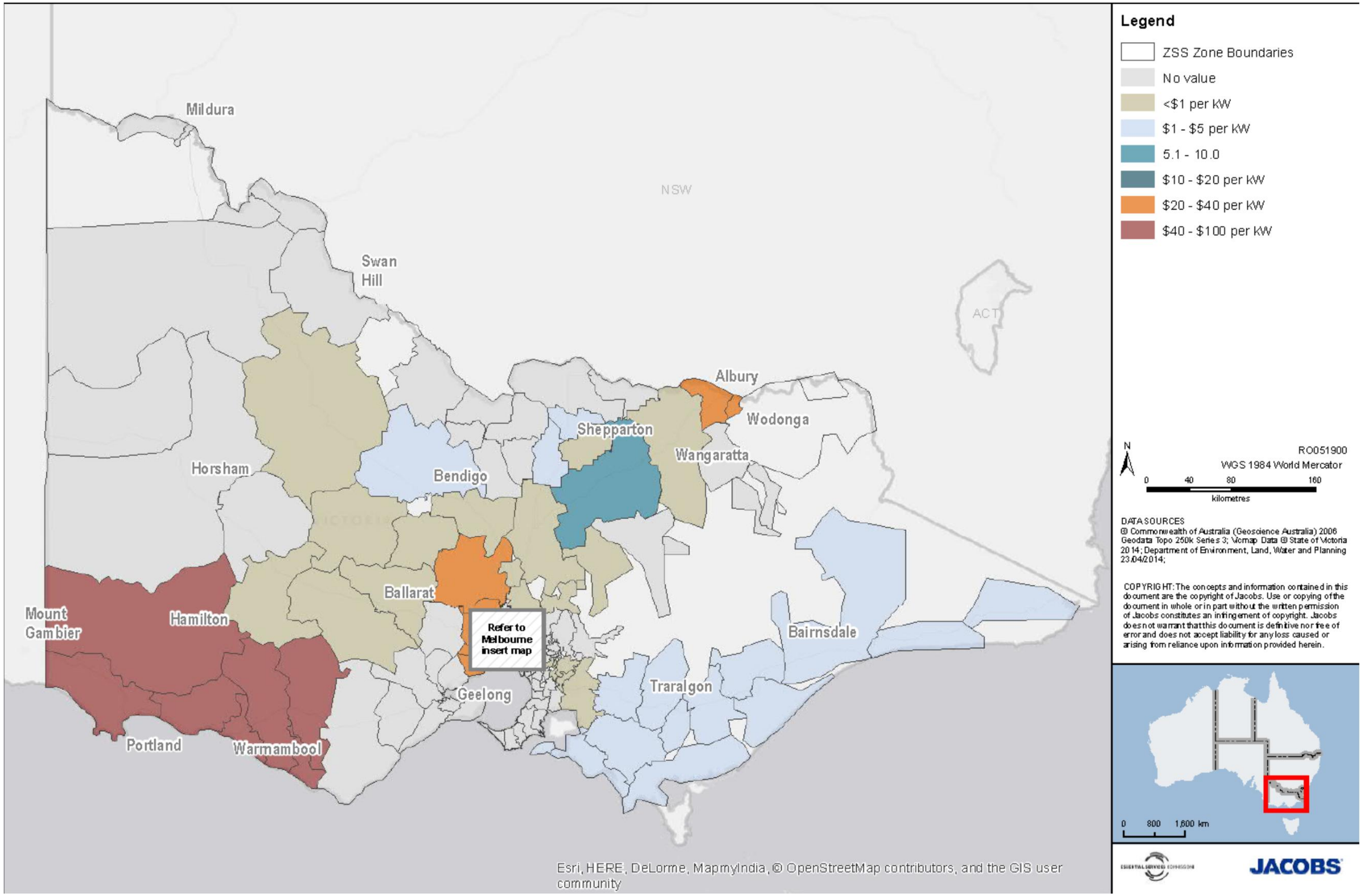


Figure 52 Specific benefit of existing PV in 2017 in Melbourne metropolitan area, $/kW/y

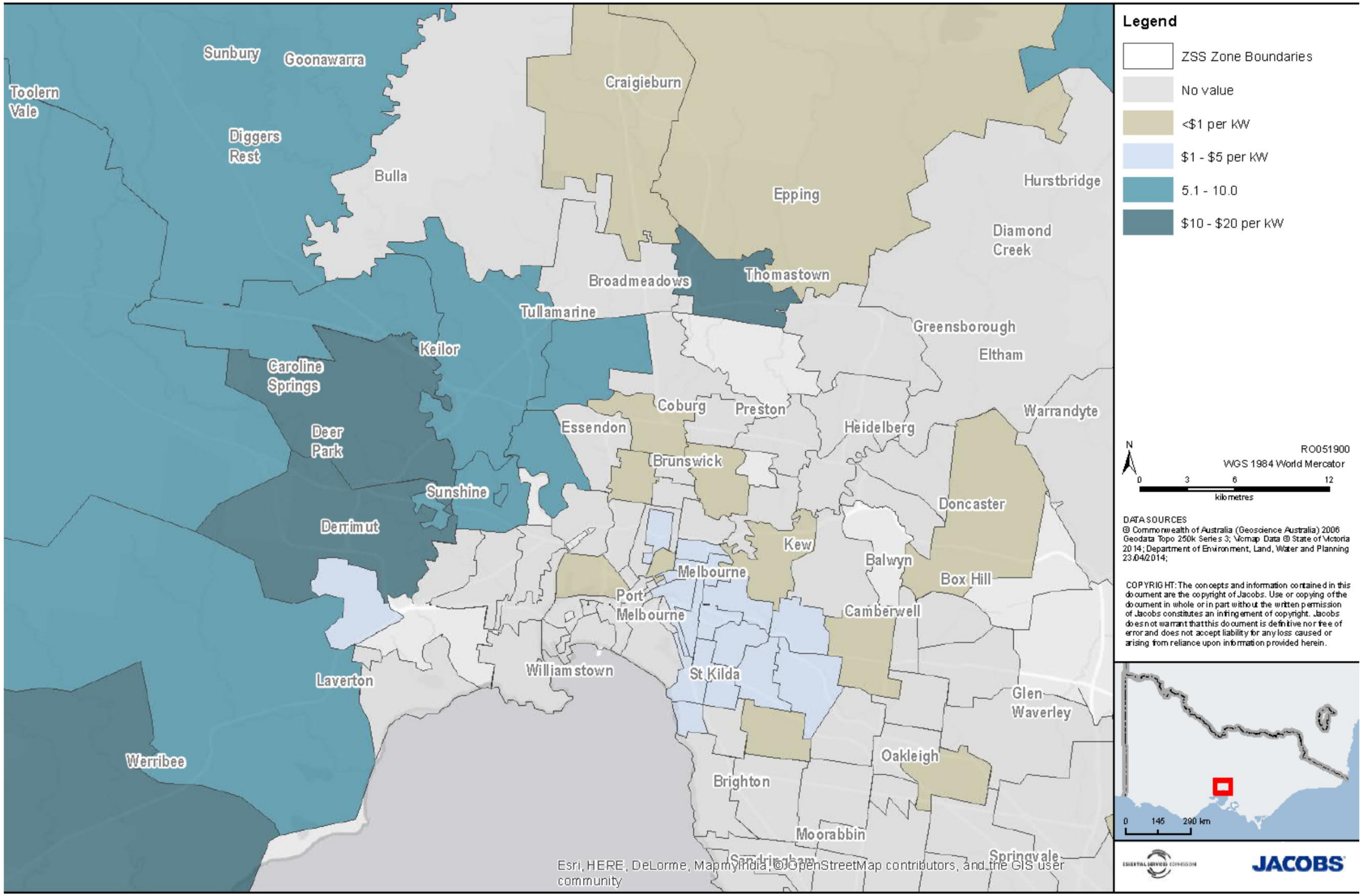
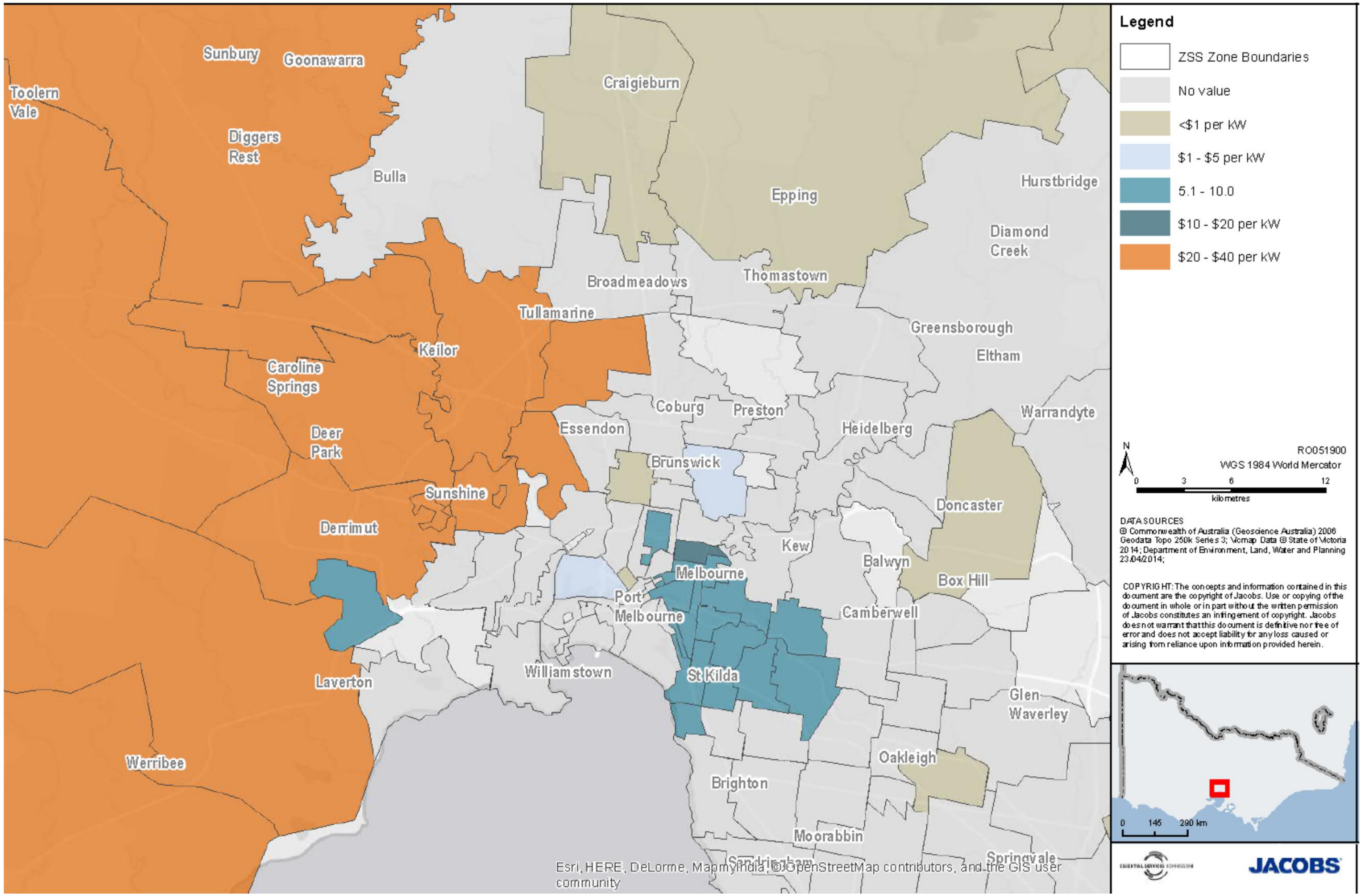


Figure 53 Specific benefit of existing dispatchable DG in 2017 in Melbourne metropolitan area, $/kW/y



C.3 Annual benefit of an incremental unit of DG in 2017

Figure 54 Benefit of incremental PV in 2017, $/kW/y

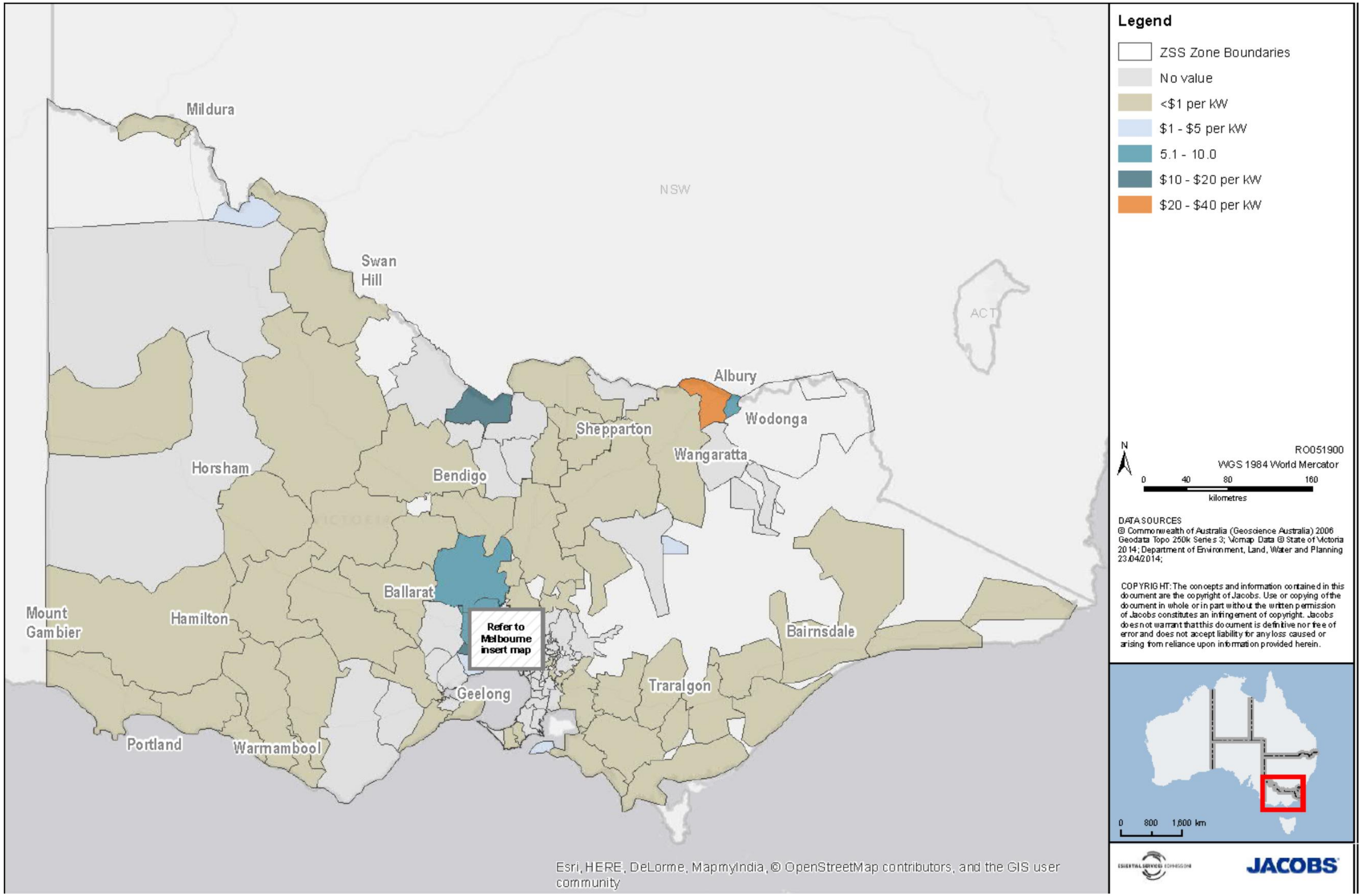


Figure 55 Benefit of incremental dispatchable DG in 2017, $/kW/y

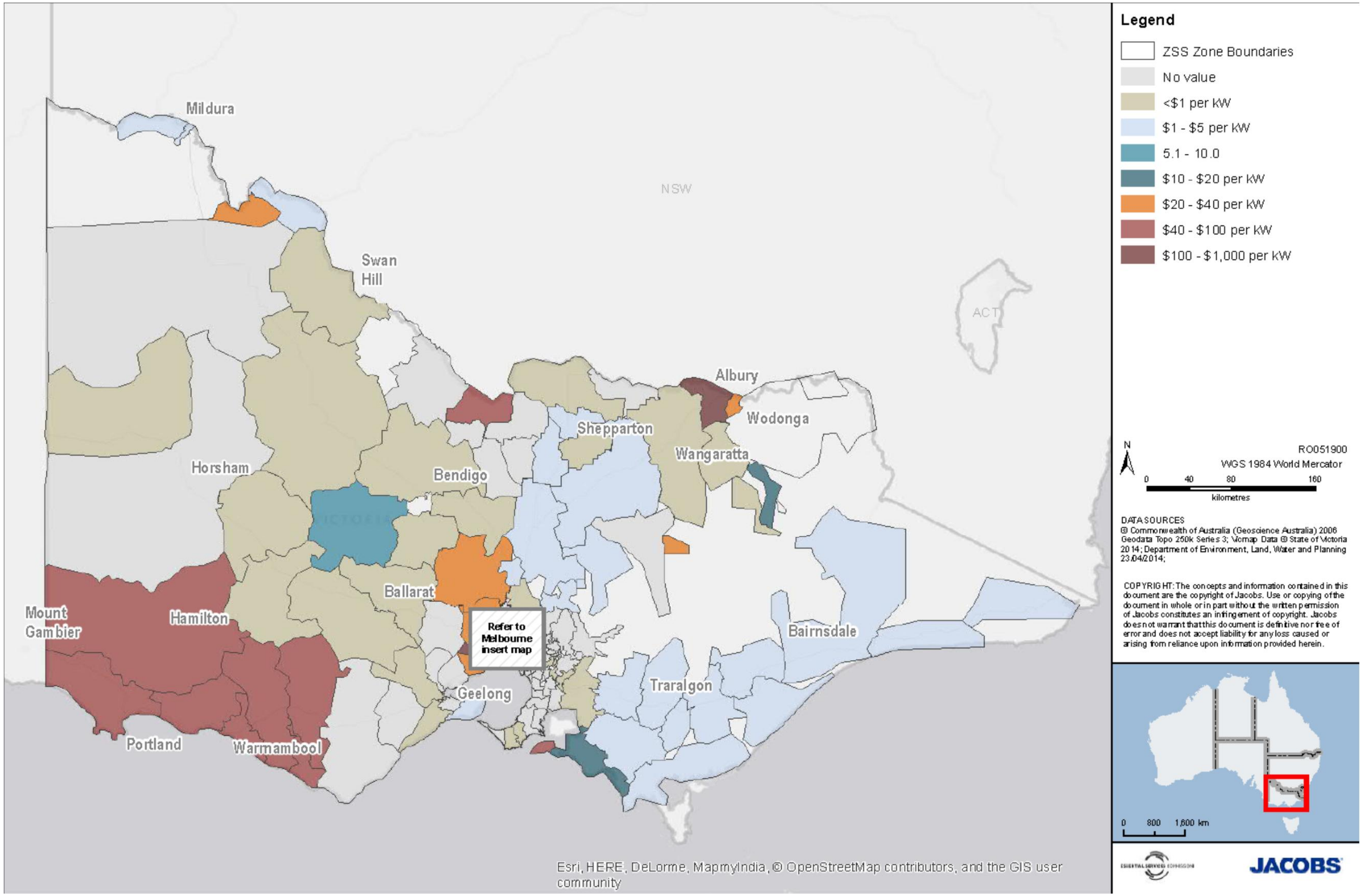


Figure 56 Benefit of incremental PV in 2017 in Melbourne metropolitan area, $/kW/y

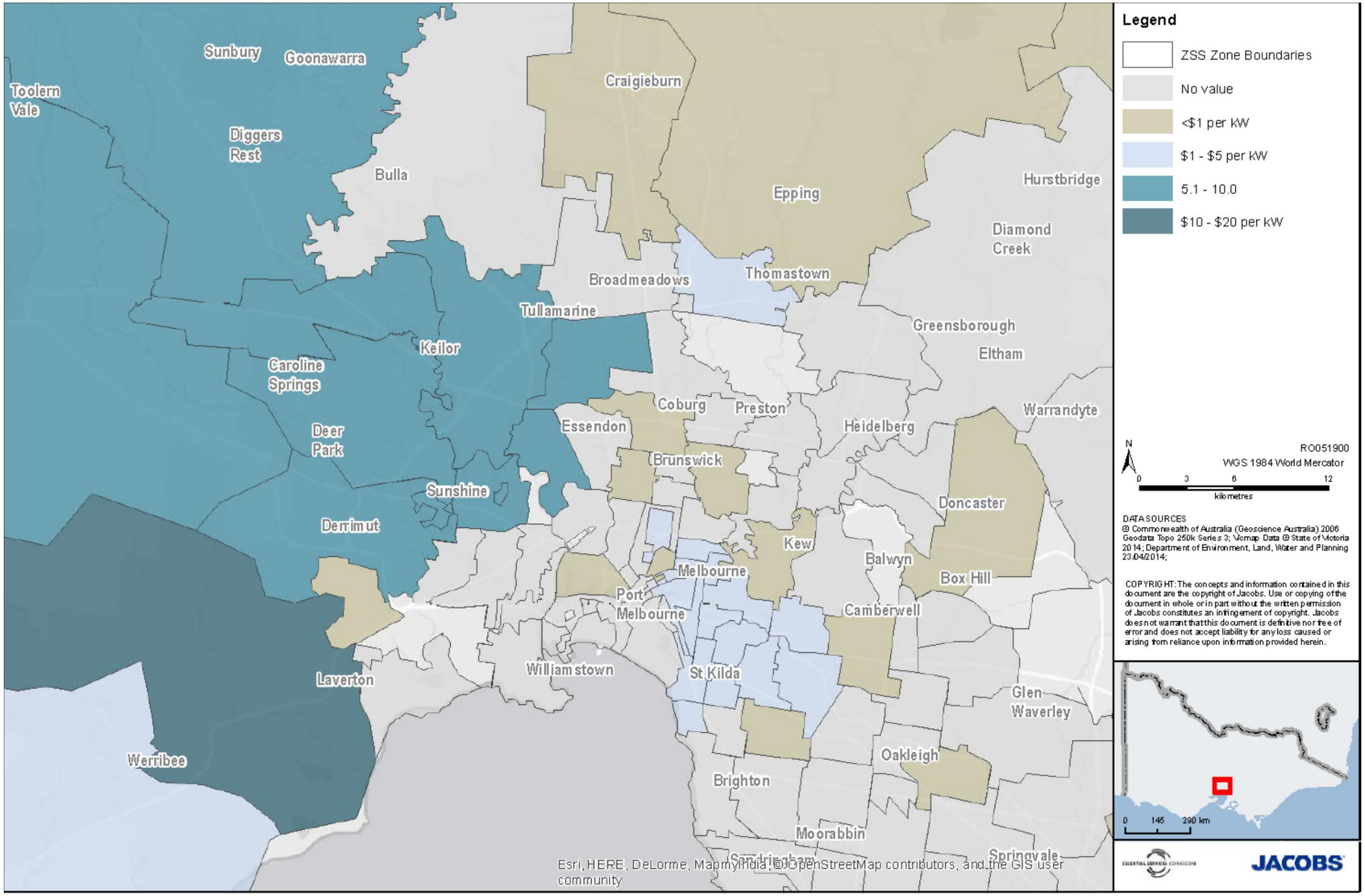
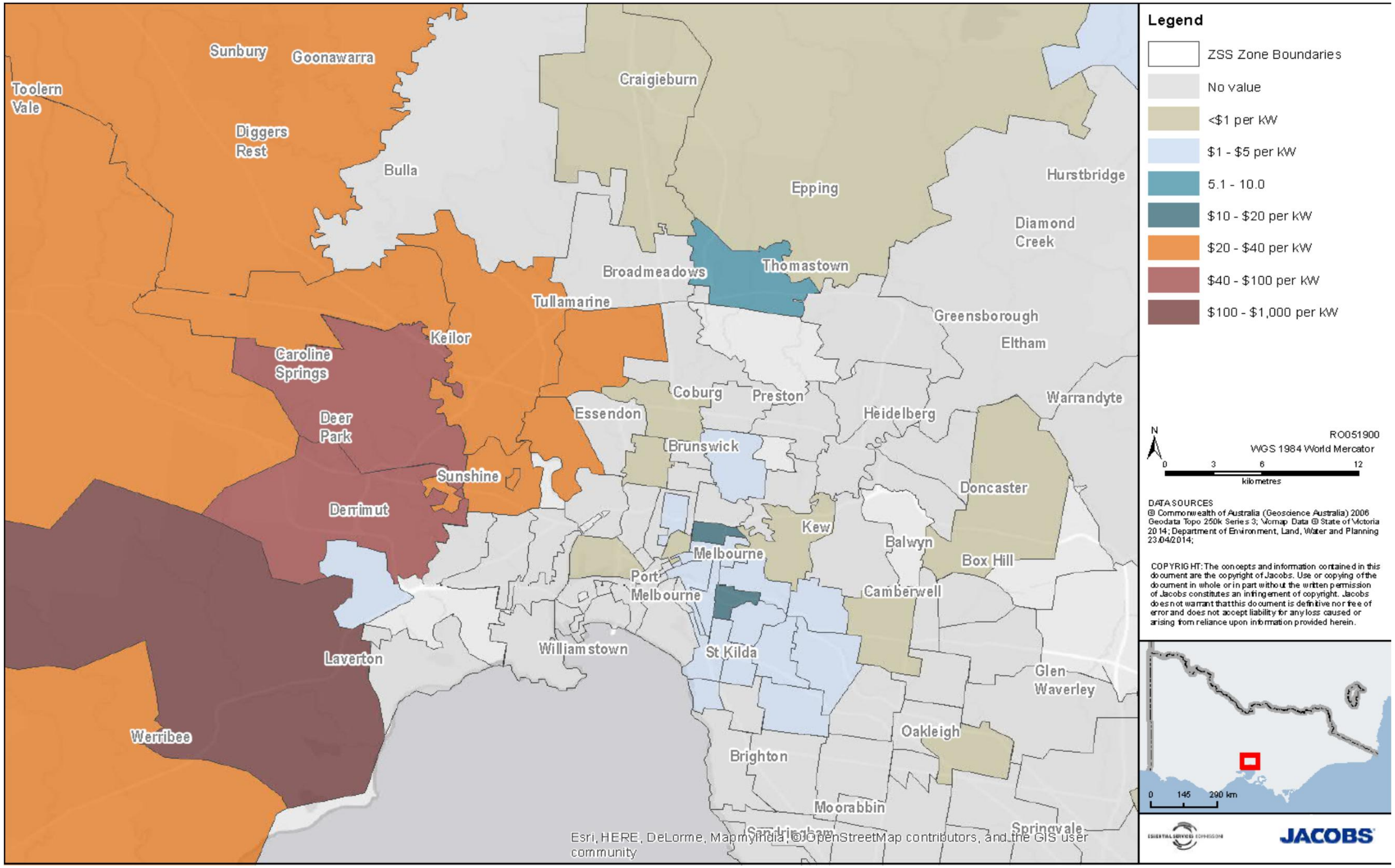


Figure 57 Benefit of incremental dispatchable DG in 2017 in Melbourne metropolitan area, $/kW/y



Appendix D. Nomenclature

AEMO	Australian Energy Market Operator (http://www.aemo.com.au/)
AER	Australian Energy Regulator (http://www.aer.gov.au/)
APR	Annual Planning Report
BoM	Bureau of Meteorology (http://www.bom.gov.au/)
Capex	Capital expenditure
CER	Clean Energy Regulator (http://www.cleanenergyregulator.gov.au/)
DG	Distributed generation – refer to Section 1.2.1 for the specific usage applied for this report
Dispatchable	In the context of this report generation that is able to produce its full rated output when called for
Distribution	Refer to Figure 6
DNSP	Distribution Network Service Provider (or “Distributor”). There are five electricity DNSPs in Victoria – • AusNet Services (http://www.ausnetservices.com.au/) • CitiPower (https://www.citipower.com.au/home) • Jemena (http://www.jemena.com.au/) • Powercor (https://www.powercor.com.au/) and • United Energy (https://www.unitedenergy.com.au/)
ESC	Essential Services Commission (http://www.esc.vic.gov.au/)
FCAS	Frequency Control Ancillary Service (used to keep the system frequency at 50 Hz under varying loads, generation outputs and system disturbances)
GST	(Australian) Goods and Services Tax
HV	High Voltage. In the context of this report 11 kV or 22 kV
Jacobs	Jacobs Group (Australia) Pty Ltd (http://www.jacobs.com/)
LRMC	Long Run Marginal Cost
LV	Low Voltage. In the context of this report 415 V
MVA	Millions of Volt-Amps. Current x Voltage. The loading parameter that is most important in sizing network elements
MVAr	The reactive (out of phase) component of the voltage and current vector product. MVAr requirements are caused by the characteristics of customer loads and of the network itself. MVAr causes a higher level of MVA for the same level of MW supplied.
MW	Millions of Watts or thousands of kiloWatts (kW). Electrical power.
N Capacity	The capacity of the network when all elements are available
N-1 Capacity	The capacity of the network when one element is unavailable (typically the largest element is taken to be unavailable)
NCAS	Network Control Ancillary Services (voltage and reactive power control of the network)
NEFR	National Electricity Forecasting Report (published by AEMO)
NER	National Electricity Rules
NTNDP	National Transmission Network Development Plan (published by AEMO)

Opex	Operations (and maintenance) expenditure
PV	Photovoltaic (power generation)
RIN	Regulatory Information Notice. Information the DNSPs and TNSPs are required to provide to AER
RIT	Regulatory Investment Test. RIT-T applies to transmission and RIT-D to distribution. A test that must (unless excepted) be applied to capex that the NSPs have to meet for capex to be allowed into the regulated asset base.
SRAS	System Restart Ancillary Services (service maintained in case the system needs to be restarted after a complete system failure)
Sub-transmission	Refer to Figure 6
TNSP	Transmission Network Service Provider (or “Transmission company”). AEMO is effectively the relevant TNSP in Victoria for this report notwithstanding the physical assets are owned by AusNet Services
Transmission	Refer to Figure 6
TS	Terminal Station. In this report, the part of the transmission system where distribution systems connect
TUOS	Transmission Use Of System charge
VCR	Value of Customer Reliability. The value ascribed to customers’ loss if electricity supply is curtailed, in $/MWh
WACC	Weighted Average Cost of Capital
ZSS	Zone substation