Decentralised Energy Costs & Opportunities for Victoria

Prepared by the Institute for Sustainable Futures
For Sustainability Victoria

Please cite this report as:
Langham, E., Dunstan, C., Cooper, C., Moore, D., Mohr, S. and Ison, N. 2011, Decentralised Energy Costs and Opportunities for Victoria, prepared by the Institute for Sustainable Futures, University of Technology Sydney for Sustainability Victoria, November 2011.

Acknowledgements
The authors would like to thank Sustainability Victoria for their support and continued input into the development and direction of this research, and the Victorian electricity network businesses Citipower-Powercor, Jemena Electricity Networks, United Energy Distribution and SP Ausnet for the provision of data, technical advice and/or review. The authors also gratefully acknowledge the support from CSIRO Energy Transformed Flagship, through the Intelligent Grid (iGrid) National Research Collaboration, under which the DANCE and DCODE modelling tools applied and refined throughout this project were developed. The authors would also like to thank iGrid Project 4 team members Peter Rickwood and Daniel May for their valuable contributions to development of the DANCE Model.

ISBN 978-1-920825-29-4 (PDF)

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Abbreviations

AER	Australian Energy Regulator
AEMO	Australian Energy Market Operator
BAU	Business as Usual (baseline scenario)
Capex	Capital Expenditure
DANCE	Dynamic Avoidable Network Cost Evaluation (model)
DCODE	Description and Costs of Decentralised Energy (model)
DE	Decentralised Energy
DG	Distributed Generation
DM	Demand Management
DNSP	Distribution Network Service Provider
DUOS	Distribution Use of System (charge)
EE	Energy Efficiency
iGrid	Intelligent Grid Research Program
ISF	Institute for Sustainable Futures
kVA/MVA	Kilo/megavolt amperes (measure of generation *capacity* or demand)
kW/MW/GW	Kilo/Mega/Gigawatts (measure of generation *capacity* or demand)
kWh/MWh/GWh	Kilo/Mega/Gigawatt hours (measure of energy consumption)
MWe/ MWp	Megawatts –electrical / Megawatts -peak capacity
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NSP	Network Service Provider
Opex	Operating (cost) expenditure
TNSP	Transmission Network Service Provider
TUOS	Transmission Use of System (charge)
WACC	Weighted Average Cost of Capital

Executive Summary

Introduction

Sustainability Victoria commissioned the Institute for Sustainable Futures (ISF) to look at the potential opportunities, costs and benefits for Decentralised Energy (DE) in Victoria, particularly in the context of reducing electricity network investment. This stemmed from Sustainability Victoria's interest in applying earlier ISF research, conducted as part of the CSIRO Intelligent Grid national research collaboration, to the local Victorian situation. ISF's Intelligent Grid research suggests that if applied strategically, DE can be a lower carbon, lower cost alternative to traditional investment in centralised energy generation and large electricity network infrastructure. Recognising the potential implications for both customers and the environment of Victoria's forecast peak demand growth trend, declining capacity utilisation of electricity network infrastructure, and a strong reliance on centralised coal-fired power generation, this research aims to help build the base of knowledge and tools to facilitate greater deployment of DE options.

There are a number of elements to this research. An assessment is made of the forecast electricity demand **trends** over the coming decade, and the electricity **network infrastructure investment** currently proposed to address these conditions over the coming five-year period. This investment is then analysed from the perspective of identifying **potentially 'avoidable' network costs** driven by growth in peak demand, which could potentially be more efficiently addressed through non-network options such as DE. This is based on the principle that a more decentralised approach to meeting electricity network constraints through demand reduction or local supply embedded within the network, can defer or avoid the need for more expensive network solutions connecting distant energy supply to consumers. Lowering the rate of growth in peak demand growth through DE can reduce the number and magnitude of constraints on the network, thereby treating the problem of peak demand growth at the source.

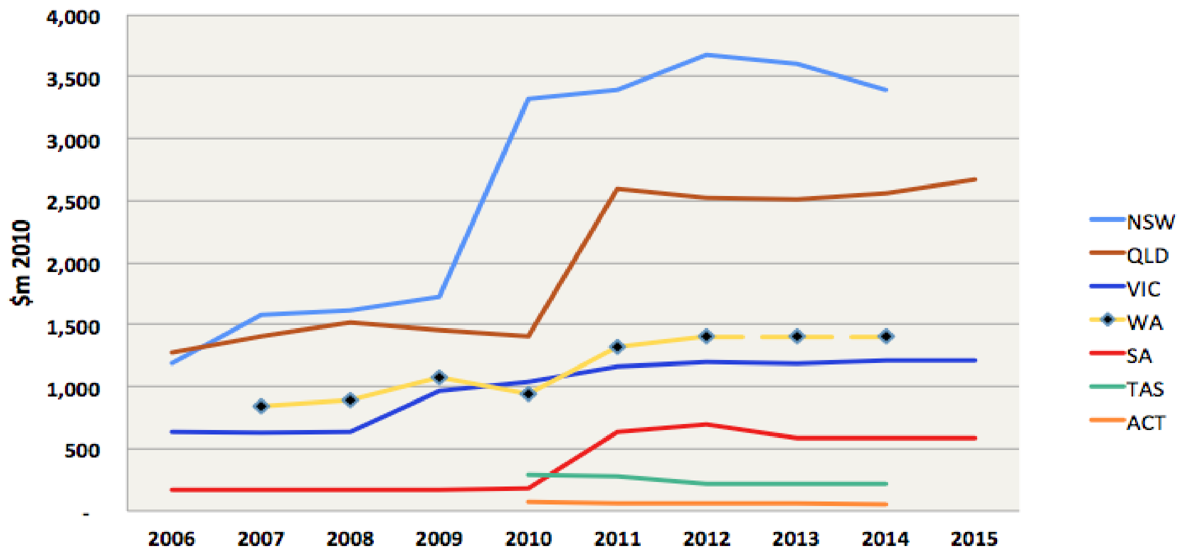
The primary output of this work is the production of **time-series maps** for Greater Melbourne, Geelong, Bendigo and Ballarat that highlight 'value hotspots' in both time and space where decentralised energy resources could potentially be applied most cost-effectively by deferring network investment. These maps are intended to make detailed network data that is currently not broadly understood, more useful to those unfamiliar with the details of network planning. Displaying this data on, simple but powerful maps is intended to assist **networks and DE service providers** who need to know or communicate the geographical areas in which the greatest benefit from DE products and services can be obtained and **policy makers and regulators** who wish to understand the dynamics of where and how DE can contribute to beneficial economic and environmental outcomes.

The analysis then looks at the potential of DE to reduce Victoria's total costs of energy supply and greenhouse gas emissions by 2020, and how these **cost savings** are passed on to customer bills.

Background

An unprecedented level of electricity network capital expenditure is planned across Australia over the next 5 years. Over $45 billion in electricity network infrastructure alone is planned for 2010-2015, as shown in Figure 2 below. This represents larger expenditure than the National Broadband Network in about half the time period. A large component of this investment is earmarked to meet growth in peak electrical demand. Note in Figure 2 the dramatic rise in investment in the regulatory period from 2010-11 onwards, particularly in NSW and Queensland. In Victoria, a lower but significant proportional jump in investment occurred of over 50 percent between the two regulatory periods, from $3.9 billion in 2006-2010 to $6.0 billion in 2011-2015.

Figure 2: Electricity Network Capital Expenditure (T&D) by Jurisdiction, 2006-2015

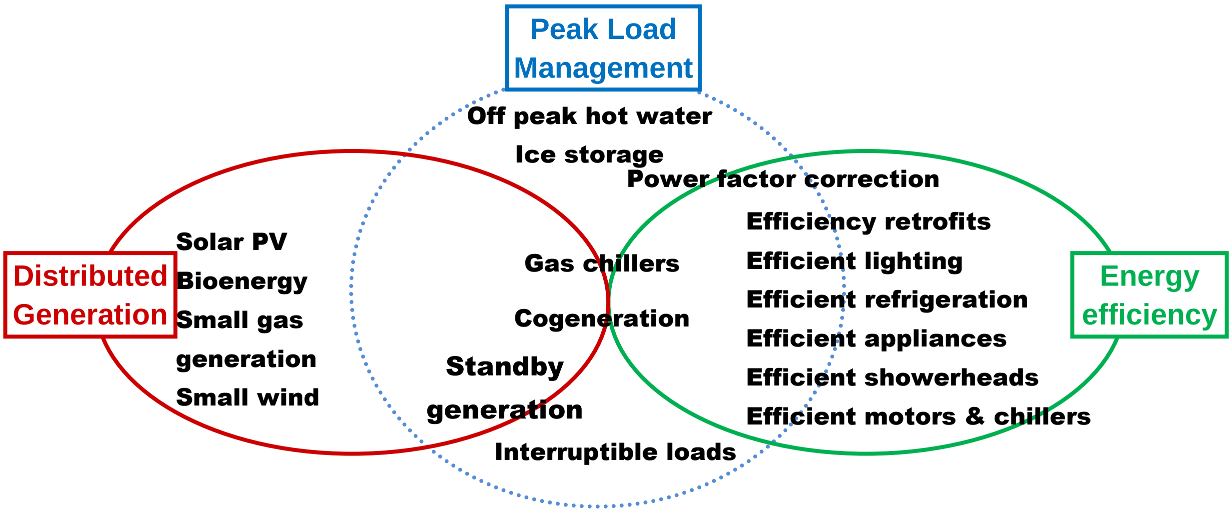


Data sources: AER and other regulator decisions (see sources for Table 1); Insufficient data available for NT

These increases are resulting in dramatic increases in electricity prices around the country. While in Victoria this trend is less pronounced than in NSW and Queensland, the four years to 2015 will see network charges increase by, for example, 32 percent in nominal terms in the case of Citipower (AER 2010), or just under 20 percent in real terms. Underlying these trends, electricity consumption in Victoria is forecast to increase by approximately 17 percent in the next ten years, while peak electricity demand is forecast to increase by 25 per cent over the same period (AEMO 2011).

The traditional approach to servicing peak demand growth through building bigger network capacity also reinforces our dependence on large scale centralised and, usually, greenhouse gas intensive power supply. However, as both the cost and global environmental impact of this traditional approach has become less acceptable, the pressure has grown for a more economically and environmentally sustainable approach. If implemented strategically, low carbon "Decentralised Energy" (DE) options can meet the twin aims of limiting increases in consumer bills *and* reducing emissions, by limiting or reversing growth in demand and the associated financial costs of delivering power from the centralised power stations. Decentralised Energy includes energy efficiency, peak load management and distributed generation, as shown in Figure 1 below.

Figure 1: Examples of Decentralised Energy resources



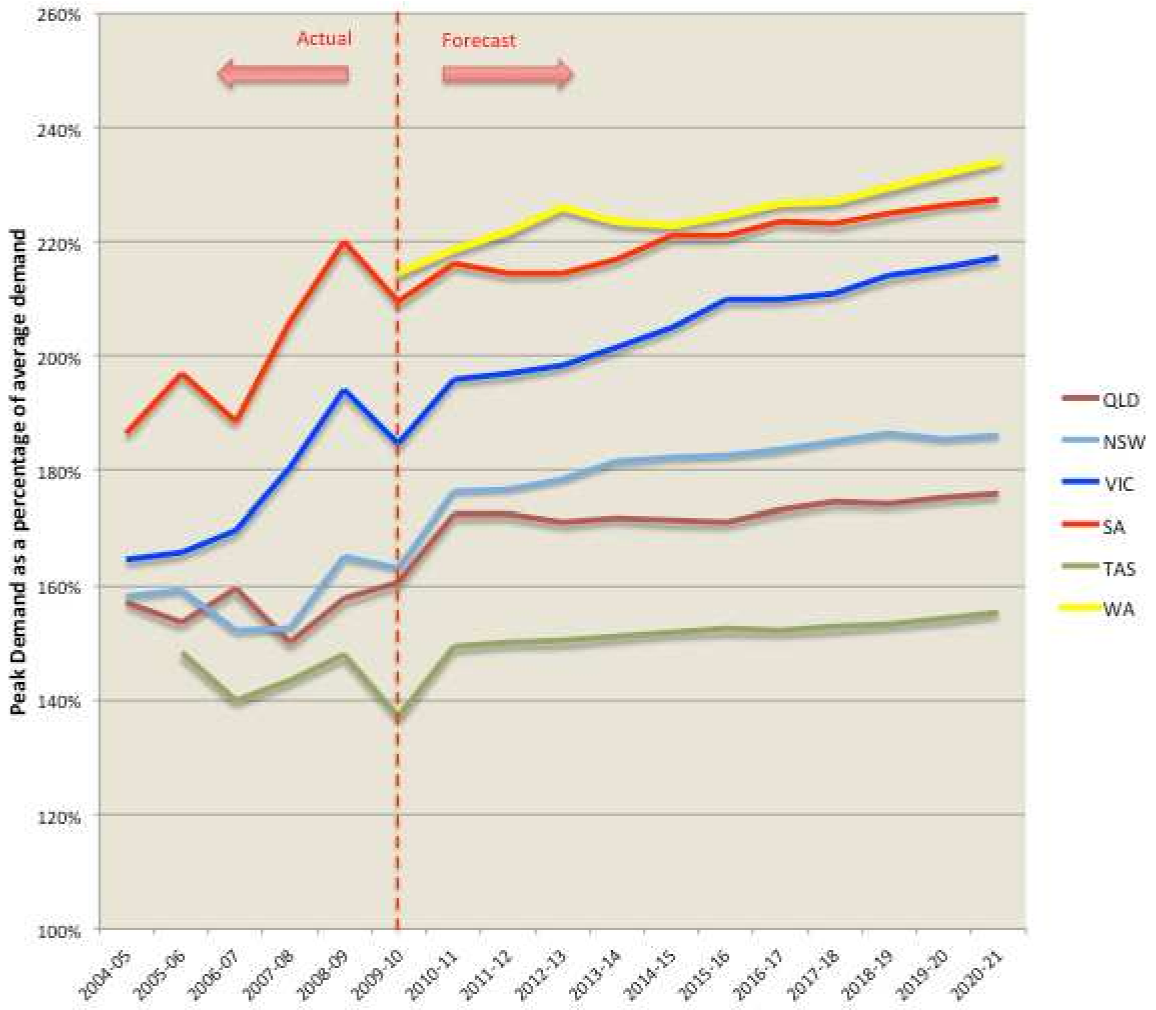
This research investigates the potential of DE to moderate peak demand growth and associated network spending in Victoria to deliver lower-cost, lower carbon electricity supply for Victorian electricity consumers.

Drivers of Network Investment

The two primary drivers of Victoria's capital expenditure on network infrastructure are ageing infrastructure replacement, as many network assets are reaching the end of their working lives, and strong growth in summer peak demand. Furthermore, Victoria's electricity demand is rapidly becoming peakier, with peak demand as a percentage of average demand increasing from 165 percent to 185 percent since 2004 (Figure 5). Figure 5 also shows that Victoria's trend of worsening network capacity utilisation is forecast to continue out to 2020 at a rate faster than all other jurisdictions. This holds significant implications for electricity prices, as higher capital expenditure on network augmentation to meet peak demand must be repaid over a relatively smaller volume of energy consumption.

Given than Victoria's rising peak demand trend is more severe than other jurisdictions yet network investment is lower, this raises the questions of how to account for the relatively lower network investment in Victoria. For example, are other states are currently 'over investing' in network infrastructure? Or is Victoria currently under-investing in networks, which may lead to future reliability problems or a significant increase in network investment in the next (2016-2020) regulatory period? Or is there some other explanation?

Figure 5: Actual and Forecast Peak Demand as a Proportion of Average Demand by State, 2004-05 to 2020-21



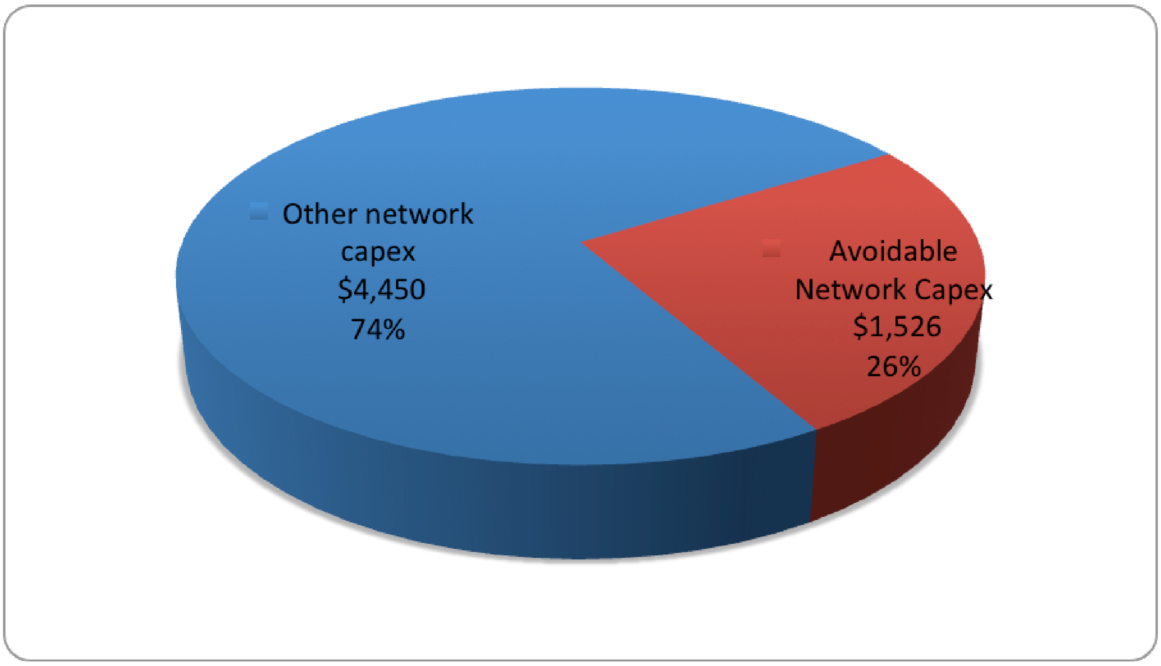
Data source: AEMO and WA Independent Market Operator 2009 Statement of Opportunities documents. Based on summer peak demand at 10% Probability of Exceedance (POE).

Calculating Avoidable Network Investment

DE can provide cost-effective alternatives to network expansion by reducing demand or increasing generation close to the source of demand. However, DE can only achieve this if strategically implemented to defer or avoid the building of *new infrastructure*. Thus, in the context of the application of DE or 'non-network' options, *avoidable* network capital expenditure (capex) is considered to be only those investments that are undertaken in response to growing peak demand ('network reinforcements'). Figure 6 shows an analysis of Australian Energy Regulator (AER) approved network spending, which reveals that Victoria's avoidable network capex (the red wedge) totals $1.5 billion, or around 26 percent of all projected network capex over the current five-year regulatory period.

The central thesis behind this research on network investment, is that if even a portion of the $1.5 billion shown in Figure 6 was redirected towards efficient DE measures to incrementally defer network augmentation, substantial economic and greenhouse gas emission savings could be achieved relative to the business-as-usual approach focused on centralised supply.

Figure 6: Victorian total and avoidable network capex 2010-2015 ($m 2010)



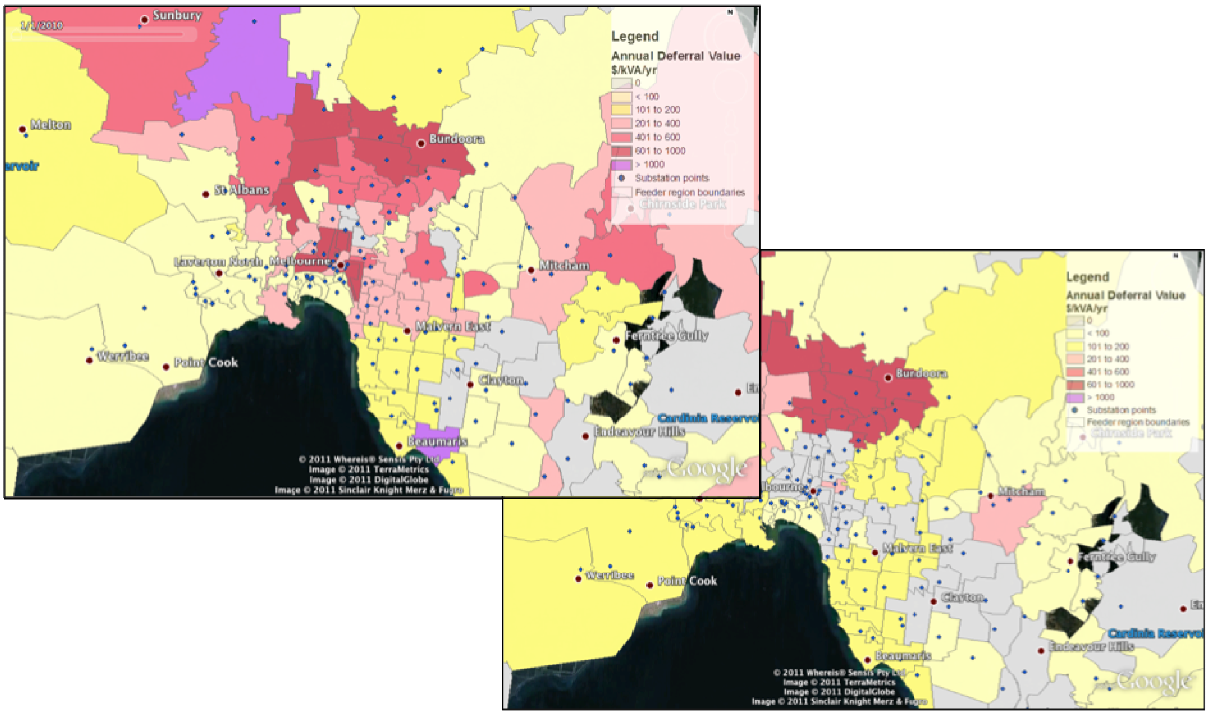
When analysed relative to the peak demand growth that these network reinforcements are addressing, in simple terms, every additional MW of peak demand costs Victorian consumers $1.1 million. When the $1.1m/MW marginal augmentation cost is adjusted for seasonal demand growth (predominantly summer peak demand in Victoria), and 'annualised' to account for the annual cost of capital and depreciation, this translates to a value of $115/kVA/yr. This represents the *average* amount of money that the network business would save annually if it could delay growth related network augmentation, and can be used as an indication of what the network should be willing to invest up to in order to support efficient DE measures. Note that this does not include the additional value to the networks that DE may be able to provide in deferring or avoiding reliability or asset replacement related network investment.

Locating Avoidable Network Investment

The annual deferral value presented above is a Victorian average, which is useful for high-level analysis of the overall potential for the assessment of avoidable network costs from DE (and is used in the later D-CODE Model analysis). However, it obscures the spatial and temporal variability of investment in network infrastructure. The smaller the geographical area of interest, the less applicable this particular average value will be. In many substation zones, the avoidable infrastructure value will be zero as there is no planned growth investment, while in others the value will be many times this average.

To highlight where this variation in annual deferral value occurs in time and space, ISF's Dynamic Avoidable Network Cost Evaluation (DANCE) Model was applied to Greater Melbourne, Geelong, Bendigo and Ballarat. The annual deferral value output for Greater Melbourne for both 2010 and 2015 is shown in Figure 14.

Figure 14: Annual marginal deferral value for Melbourne in 2010 (L) and 2015 (R)



Areas in grey are those with no deferral value, marginal deferral value increases strongly in the areas where the pink and purple colours intensify ($400 to >$1000/kVA/yr), which are the areas where DE can be highly attractive to networks and proponents. Note that in 2010 (left), there are many regions where cost-effective DE opportunities are available; while in 2015 (right) many of these opportunities have disappeared. This is because the investment planned for many of those regions has been spent, eliminating the possibility of deferral. What the 2015 image does not show, however, is that there would be new network investments appearing each year with every updated network planning report. Given that we do not yet know where these are going to be, they cannot be mapped and thus the annual marginal deferral value shows far less opportunities in 2015 than in 2010.

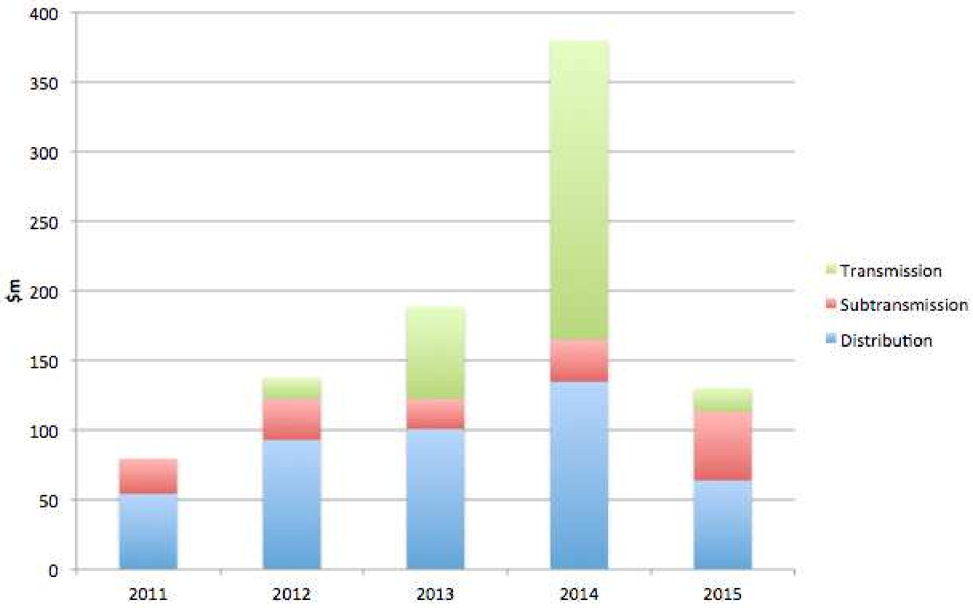
The DANCE Model map outputs are provided in interactive Google Earth format as a complement to this report, and include a host of other images such as deferral value across the months of the year and across the hours of the peak summer day, available network capacity and locations of proposed network investment. Appendix B of this report contains user instructions for the DANCE Maps. Google Earth can be downloaded freely from: earth.google.com

In producing the investment analysis and visual output tools DANCE seeks to assist the following stakeholders to better engage with the potential of DE:

- Distribution (and transmission) network businesses;
- Policy makers and regulators; and
- DE service providers.

This mapping process found that despite the lower marginal cost of network augmentation in Victoria relative to other jurisdictions, there are still a large number of “value hotspots” for DE application to alleviate network constraints. An analysis of the timing and type of planned network investment reveals that the major year for investment in network infrastructure is 2014, followed by 2013, then 2012 and 2015 (illustrated in Figure 19). This is promising in that there are numerous opportunities for the promotion and uptake of DE as network demand management if it was to be made a policy priority.

Figure 19: Size, timing and type of growth-related investment reported in Annual Planning Reports



Data Source: Distribution and Transmission Annual Planning Reports

Costs and Potential of DE in Victoria

The above sections quantified the potential avoidable network investment, and mapped where within the electricity network those avoidable costs occur. This raises the question of to what extent Decentralised Energy options can deliver these network cost savings cost-effectively. This question is answered through the application of the Description and Costs of Decentralised Energy (D-CODE) Model at the Victorian state level. While there are many models of the costs of different energy supply options, D-CODE approaches the problem from a different perspective, by:

- including often “hidden” network costs associated with the geographical location of electricity generation relative to electricity consumers; and
- assessing supply-side and demand-side options on a level footing.

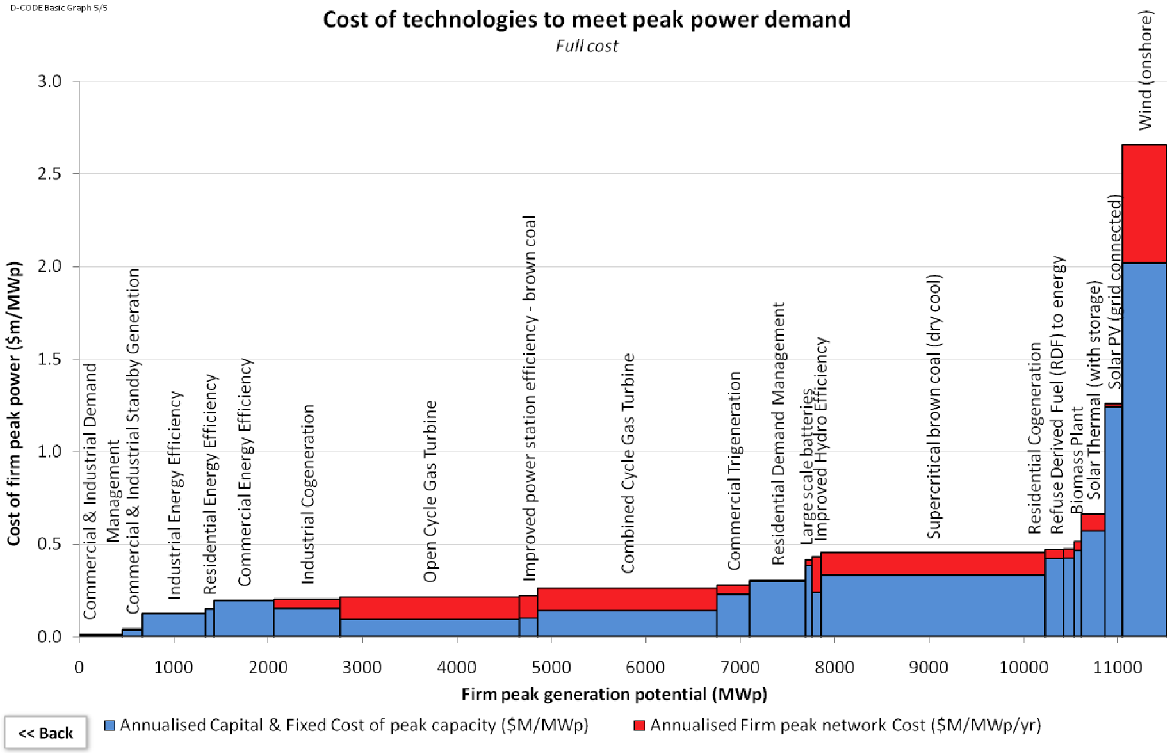
As DE options – particularly those on the demand-side – can avoid the need for major network infrastructure costs associated with more centralised supply options, D-CODE reveals the benefits of DE options over centralised generation expansion. These benefits are generally overlooked in a typical levelised cost analysis of generation options.

The populated D-CODE Excel spreadsheet with pre-loaded Victorian data is supplied as a deliverable with this report for users to investigate their own energy sector scenarios.

The D-CODE analysis finds that, contrary to conventional wisdom, **in order to meet peak capacity constraints, the cheapest options are not gas peaking plants, but rather commercial and industrial peak load management and energy efficiency** (Figure 22). A similar analysis is performed regarding meeting energy generation constraints (see body of report for graph), where it is found that the **cheapest energy generation options are not coal-fired baseload power stations, but energy efficiency and some forms of distributed generation.** It is important to note that these conclusions are reached *before* a price is included on carbon. If a carbon price is included in the analysis, the financial advantages of energy efficiency and peak load management over coal and gas generation options are even more pronounced.

In the cost curve in Figure 22 below, the vertical axis represents the costs, which are broken down into components (represented by different colours) and the horizontal axis represents the quantity of that technology that could potentially be developed in Victoria. Importantly, these graphs include network cost estimates associated with each technology (in red), and therefore highlight the benefits of DE options (through avoiding the need for network infrastructure), which are typically not captured by standard levelised cost comparisons.

Figure 22: Cost and potential of supplying peak power ($m/MWp)



Based on a review of the literature, industry and other sources, the DE potential in Victoria represented in Figure 22 totals:

- 4,270 MW of peak capacity potential (32% of 2020 peak demand); and
- 16,407 GWh per annum of energy generation potential (31% of 2020 energy demand).

D-CODE's Optimum Mix Analysis (OMA) was then used to model the lowest cost deployment of technologies and programs to meet the future energy needs of Victorian electricity system, to determine how much of this DE capacity is cost-effective relative to Business-as-usual centralised supply options.

According to AEMO (2010), based on forecast demand and current and planned generation investment Victoria faces a *peak capacity* shortfall in generation capacity of 2,244 MW in 2020-21, while its existing generation is sufficient to meet *energy demand* in 2020-21 with a reasonable surplus, assuming that no existing generation assets are retired. There are, however, several coal-fired generation assets that have already passed or will pass their scheduled working lifespan of approximately 40 years, including (by 2010-11) Hazelwood, Yallourn W, Anglesea and Morwell; and (by 2014-15) Loy Yang A. It is for this reason that although there is no energy shortfall if these power stations continue to operate beyond their projected lifespan, an additional scenario is run to explore the role that DE could play if 1600MW of brown coal generating capacity was retired.

To explore the costs and potential for cost-effective DE in Victoria, three scenarios were run:

1. Business as Usual ('BAU': includes 20% Renewable Energy Target and excludes consideration of network costs).
2. Decentralised Energy deployment ('DE': includes 20% Renewable Energy Target; based on lowest cost deployment of *all* technologies but with consideration of network costs).
3. Coal Retirement: As per Scenario 2 with end-of-life retirement of 1600 MW of coal-fired power generating capacity.

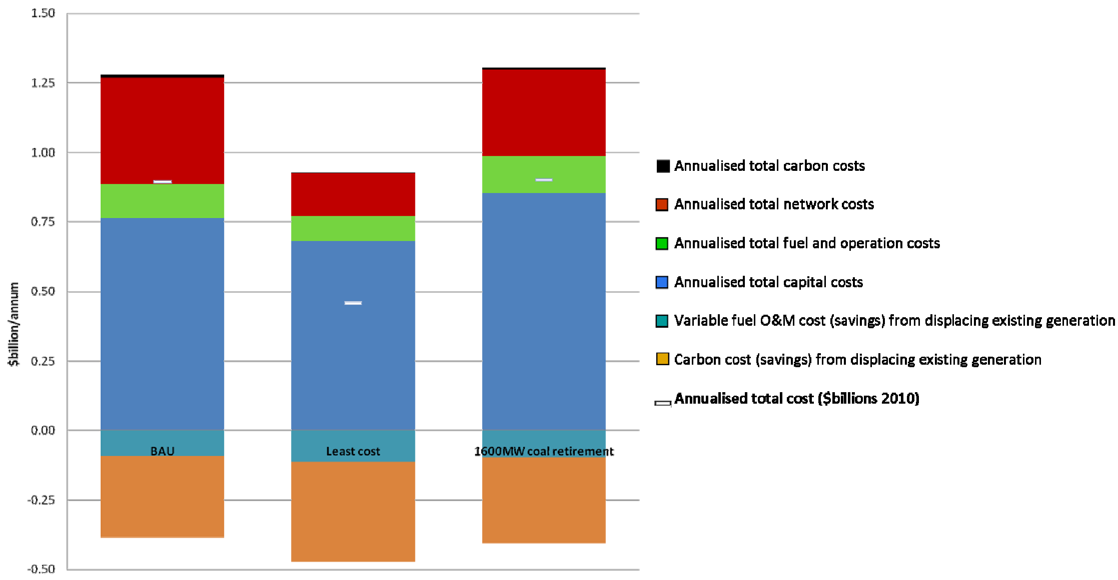
In Scenario 1, the capacity shortfall was largely met through gas-fired peaking power plants and renewables (forced into the mix by the Renewable Energy Target). In Scenario 2 the capacity shortfall was largely met through energy efficiency, peak load management, and renewables (again, forced into the mix by the Renewable Energy Target), without any further centralised fossil fuel capacity. In Scenario 3, when an energy shortfall is created, the mix becomes much more diverse, with 90 percent of the energy shortfall made up by a range of DE options and renewable energy, and 10 percent of capacity coming from new gas-fired peaking plants.

The comparative costs of these scenarios are shown in Figure 29 below. Due to some elements being represented as costs (those above zero on the y-axis) and others as benefits or cost offsets relative to the current situation (those below zero on the y-axis), the total final costs for each scenario are shown as a white dash in Figure 29. The total cost (white dash) is the value of the costs (the highest part of the coloured column) minus the value of the benefits or cost offsets relative to the current situation (the part below zero on the y-axis).

The **DE scenario was found to save consumers $437 million per annum relative to BAU**, more than half of which was due to reduced expenditure on electricity delivery (networks), and the remainder due to lower fuel and operational costs associated with DE technologies (particularly demand-side options), and reduced carbon cost liability. This scenario also led to emissions reductions of 3.3 Mt per annum (a 6 percent reduction on BAU 2020 electricity emissions), at a net benefit of $110 for every tonne of CO_2 abated.

It was also found that if 1600 MW of brown coal generation was retired at end-of-life, DE could largely fill the additional energy and peak capacity shortfalls at an additional cost of $7 million per annum, or an incremental cost of 0.8% as compared to the BAU case. In this case, emissions would be reduced by 6.5 Mt per annum (a 12 percent reduction on BAU 2020 electricity emissions), which translates to a carbon abatement cost of around $4 per tonne.

Figure 29: Annual cost of supplying energy and capacity shortfalls in 2020 under different scenarios ($2010 billions p.a.)



Consumer Benefits of DE in Victoria

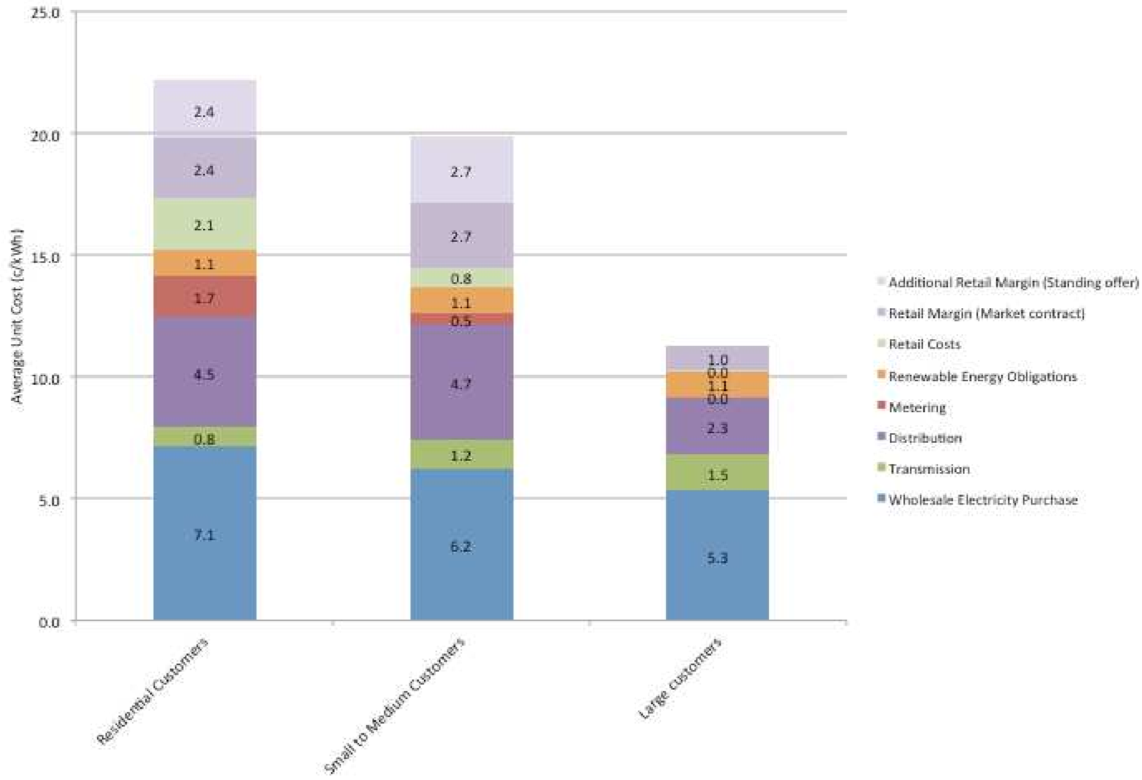
Figure 35 shows a breakdown of the average unit cost of electricity for residential, small business and large business customers. For all three customer classes, wholesale energy costs make up the single largest component, contributing between 5 and 7 c/kWh. Network charges, including both distribution and transmission components make up the next most significant contributor, at around 5 to 6 c/kWh for the two smaller customer classes and 3.8 c/kWh for large business. As a percentage of the final customer bill, network charges translate to around 25 percent for residential customers, which are a substantially smaller proportion than in other jurisdictions.

The implementation of the DE scenario (D-CODE Scenario 2 earlier) included deployment of large amounts of Decentralised Energy technologies, primarily to meet Victoria's peak capacity constraint by 2020-21, which result in a $437 million saving to consumers. This saving is passed on to consumers through the net impact of the following changes:

1. ***Price* component reductions:**
   a. Savings in **electricity network prices** (green and purple tariff components) due to reduced infrastructure spending from DE deployment, partially offset by the cost of peak load reduction measures borne and passed through by network businesses.
   b. Savings in **energy generation prices** (blue component) resulting from reducing price spikes in the National Electricity Market, although these have not been assessed in this study.
2. ***Price* component increases:**

  a. ***Network prices*** (green and purple tariff components) concurrently increase in price as sunk infrastructure expenditures need to be repaid over a lower volume of electricity sales, due to energy efficiency deployment.
  b. ***Retail costs*** (light green component) increase to pay for energy efficiency costs, if they are borne by retailers and passed through to customers such as through a white certificates scheme.
3. ***Volume* reductions:**
  a. **Savings in full retail rates** (all tariff components) due to customers purchasing less kWh of electricity, resulting from participation in end-user energy efficiency activities.
  b. **Avoided carbon costs** associated with the volume of reduced energy consumption of that customer class (not shown in tariff analysis).

Figure 35: Electricity costs by customer classes
(Citipower 2011 - average c/kWh incl. standing/demand charges)**)**



The net impact of all competing impacts 1,2 and 3 above on customer bills ($ per customer per year), **translates to an average saving in customer bills of 4.7%.** This total reduction in bills is the net impact of reduced spending due to the reduction in kWh consumption, and the average price increases to account for the lower volume of energy consumption.

Table 13 below shows what the above price and volume impacts might look like on different customer classes in dollars per customer per annum. These calculations work out differently for different customer classes, but hinge strongly on the amount of energy efficiency undertaken within that sector. Where customers undertake a greater level of energy efficiency, bill reductions are greatest.

Table 13: Customer bill changes in 2020 from DE Deployment ($/customer/annum) #

	Residential	Small-Medium Business	Large Business
Price effect	+$0.85	+$103.08	+$5,440.76
Volume effect	-$22.88	-$340.25	-$10,609.62
Carbon cost	-$2.09	-$30.03	-$1,501.32
TOTAL CHANGE	**-$24.12 (-1.3%)***	**-$267.20 (-4.3%)***	**-$6,670.18 (-3.5%)***

*Notes: # - Positive numbers represent an increase in bills and negative numbers represent a decrease in bills; * - Percent change in total annual bill including carbon liability.*

Given that much of the consumer benefits are associated with the reduction of consumption, it is important to recognise that consumers will primarily benefit as *participants* in energy efficiency activities. Thus if all customers are to benefit, care must be taken by policy makers in addressing institutional barriers to the uptake of energy efficiency, to ensure that cost-effective residential, commercial and industrial energy efficiency opportunities are tapped.

Conclusions

This research indicates that there is substantial untapped cost-effective potential of DE in Victoria, which if implemented strategically, could reduce electricity sector emissions by 6.2% and save electricity consumers in the order of $437 million per annum by 2020. It is estimated that this saving would result in reductions in average consumer bills of 4.7%.

Furthermore, tackling challenges such a gradual retirement of coal-fired generation as they reach the end of their economic life are found to be manageable with DE options in the sectoral mix. DE increases the range of options to tackle future peak capacity and energy generation shortfalls in a more dynamic, cost effective and flexible fashion. Victoria is well placed to initiate and develop more flexible processes towards adopting DE in network development, as it already operates on a probabilistic network planning model and instituting similar processes for DE application is a small step from current practices relative to other States which are based on deterministic investment triggers.

Through the delivery of customised DANCE and D-CODE Models for Victoria, this research provides valuable tools for policy makers, electricity network businesses, and DE service and technology providers to identify the optimal timing and location of DE opportunities and to build a functional and responsive Demand Management industry in Victoria.

While Victoria currently faces one of the lower marginal costs of new network supply in the country, this research raises questions about the future direction of electricity network expenditure in Victoria, given its unusual situation of relatively high peak load growth and relatively low network capital expenditure. Victoria may therefore be well placed to take advantage of this “window of opportunity” to act in advance of other states, before Victoria’s strong summer peak demand growth drives reliability concerns and more substantial new network expenditure, placing additional price pressures on electricity consumers.

Such a DE strategy could allow Victoria to take a step change towards a more flexible, low-carbon decentralised energy future, while avoiding the severe electricity cost pressures seen in NSW and Queensland. This DE strategy would also reduce the risks of the Victorian electricity sector being exposed in the 2016-2020 to a combination of reliability problems, declining load factors, rising network capital expenditure, and rising prices, customer bills and carbon costs.

1 Introduction

1.1 Network costs and Decentralised Energy

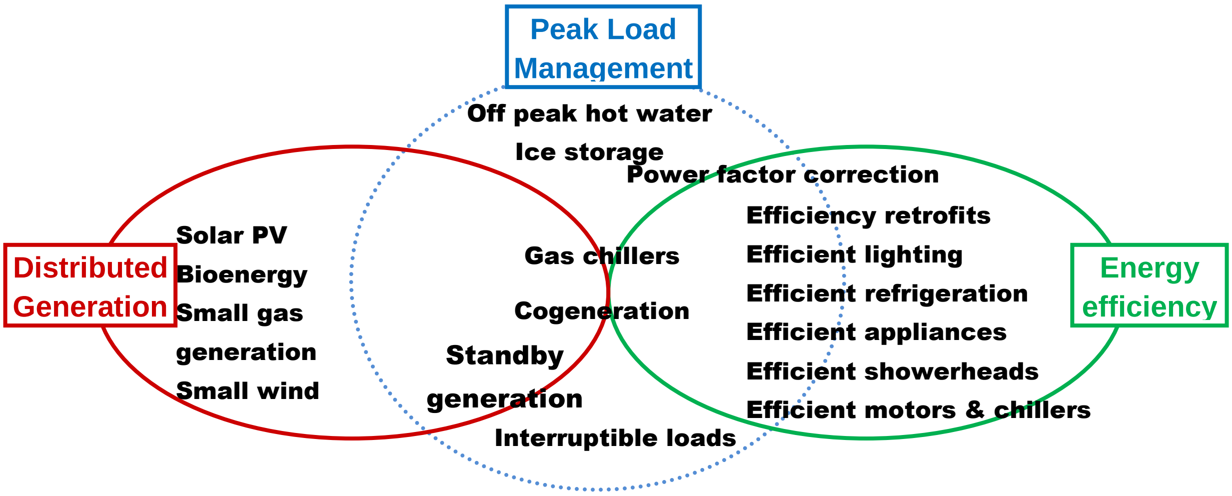
Electricity consumption in Victoria is forecast to increase by approximately 17 percent in the next ten years,[1] while peak electricity demand is forecast to increase by 25 per cent over the same period (AEMO 2011). This broadly reflects of the national situation, albeit with a slower growth rate. An unprecedented level of electricity sector capital expenditure is planned over the next 5 years, a large component of which is to meet this growth in peak demand. Over $45 billion in electricity network infrastructure alone is planned for 2010-2015, which represents a larger expenditure than the National Broadband Network in about half the time period. Electricity generation infrastructure will add significantly to this figure. This unprecedented expenditure is resulting in dramatic increases in electricity prices around the country. While in Victoria this trend is less pronounced than in NSW and Queensland, the four years to 2015 will see network charges increase by 32 percent in nominal terms in the case of Citipower (AER 2010), or just under 20 percent in real terms.

The traditional approach to servicing peak demand growth through building bigger network capacity also reinforces our dependence on large scale centralised and, usually, greenhouse gas intensive power supply. However, as both the cost and global environmental impact of this traditional approach has become less acceptable, the pressure has grown for a more economically and environmentally sustainable approach. If implemented strategically, low carbon "Decentralised Energy" (DE) options can meet the twin aims of reducing consumer bills *and* reducing emissions, by limiting or reversing growth in demand and the associated dollars costs of delivering power from the centralised power stations.

Decentralised Energy can reduce costs for consumers by addressing infrastructure constraints caused by periods of high electricity demand at peak times from *within* the electricity network. Reducing peak electricity demand through energy efficiency or load management (the green and blue circles in Figure 1 below), or generating power close to the consumer using 'distributed generation' (the red circle in Figure 1), can reduce the need for expensive transmission and distribution infrastructure upgrades to supply more peak power to that network area from distant centralised generators long distances. This benefit is a central element of this research.

[1] This is a dramatically higher forecast than the previous year, which anticipated a 10 percent increase over ten years (AEMO, 2010).

Figure 1: Examples of Decentralised Energy resources
(adapted from IPART 2002, p. 102)



1.2 The Victorian Situation

Victoria, while facing increases in approved electricity network capital expenditure out to 2015, has to date been affected less dramatically than other jurisdictions, such as NSW and Queensland. Yet the underlying trend of an increasingly peaky electricity demand is strong and there are questions as to where electricity network investment may be heading in the coming years beyond the end of the current regulatory period in 2015. Moreover, the major changes to electricity supply systems that are expected flow from the need to reduce carbon emissions are likely to have significant, but as yet unclear, implications for electricity networks. Thus, just as Melbourne benefited from a "conservative" decision to retain its tram network when other Australian cities decided to abandon theirs in favour of a greater reliance on cars, Victoria stands out as one jurisdiction where a more measured approach to planned and future electricity network capital expenditure to meet peak demand growth could reap significant economic benefits.

Recognising the potential implications of the forecast peak demand growth trend, this research has been commissioned to assist in facilitating the most cost-effective application of DE options as lower-carbon alternatives to Victoria's traditional investment in electricity network and generation infrastructure (which delivers primarily brown coal based electricity over long distances to consumers).

1.3 How DE benefits are captured in Victoria

Given the structure of the regulatory system, the way that the economic benefits of DE could be realised by Victorian electricity consumers is as follows:

1. Electricity network businesses are encouraged and supported to implement DE options at sufficient scale to defer or avoid capital intensive network upgrades (such as poles, wires and substations) during the current regulatory period (2010-15). This may include network businesses being encouraged to offer incentives for DE proponents to improve the business case for these technologies and increase the level of DE uptake;

2. Lower peak demand growth means less than the forecast and AER-approved network infrastructure investment is required by distribution and transmission network businesses out to 2015. During the current regulatory period, the economic savings are shared between:
   a) Consumers that participate in implementing DE measures, through lower electricity purchases or capacity charges;
   b) DE Providers, if incentives are offered to those technologies to reduce peak demand; and
   c) Electricity network businesses, through reduced capital expenditure in new poles, wires and substations. However, note that distribution network prices[2] are not affected during the current regulatory period, as these businesses operate under a regulated price cap.
3. If energy efficiency measures are pursued through retailer obligations such as a white certificate scheme,[3] additional costs will be passed through to consumers within the retail cost component of electricity prices. For customers participating in DE initiatives, these price increases are offset by reductions in consumption. However, all consumers may also benefit indirectly from lower wholesale energy generation costs as a result of lower overall and peak demand in the wholesale energy market. These benefits of DE, which may be significant, are not quantified in this research.
4. The benefit to network businesses of reduced capital investment is offset by reduced electricity sales and the cost of any incentives to support DE borne by the network businesses. Some policy mechanism to ensure that networks are not unfairly disadvantaged in this process may be required to “decouple” network profits from sales volume, such as, by the shift from a Price Cap to a Revenue Cap regulatory model, or the introduction of a sales foregone recovery mechanism such as the ‘D-Factor’ Scheme in operation in NSW.
5. In subsequent regulatory periods (beyond 2015), if cultural and other institutional barriers are overcome and network businesses become more familiar with the DE alternatives to network augmentation, networks become more inclined to plan in extensive DE solutions, which limits the need for new growth-related network expenditure in the upcoming regulatory period. The lower rate of growth in peak demand due to DE implementation reduces the number and magnitude of constraints on the network, treating the problem of peak demand growth at the source.

In practice, the main economic benefits of a well-implemented DE strategy may never be ‘visible’, in that DE should assist Victoria in avoiding the even steeper electricity price path being felt by NSW and Queensland in the current regulatory period.

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[2] Network charges are the separate component of customer bills that pay for the investment in upkeep and expansion of electricity poles, wires and substations. These are commonly known as Distribution and Transmission Use of System (DUOS/TUOS) charges.
[3] Such as an extension to the Victorian Energy Efficiency Target scheme (VEET).

1.4 Research Structure

This research aims to achieve the goal of furthering the application of cost-effective DE through several components:

1. An analysis of approved electricity network expenditure from 2011-2015 (Section 2);
2. An analysis of the proportion of approved network expenditure considered "avoidable" through moderating peak demand growth (Section 3);
3. Mapping specifically *where* (geographically) within the electricity network these avoidable or deferrable network cost opportunities can be found over the next five years. This shows us the locations for the most cost-effective application of DE (Section 4);
4. A high-level analysis of the market potential and costs of efficient DE application in Victoria, taking into account the avoidable network costs calculated in Section 3 above (Section 5). This establishes the potential gross cost savings for Victoria through DE implementation;
5. The impact that DE implementation at the scale modelled in Section 5 would have on reducing electricity price rises (through reduced network charges) and customer bills (through reducing consumption) (Section 6). This is underpinned by an analysis of Victorian electricity prices to determine the proportion contributed by network charges; and
6. Conclusions on the key findings of relevance for the Victorian Government stemming from this research (Section 7).

This research will inform not only the potential economic benefits for all consumers from DE application in Victoria, but also the potential value up to which DE proponents should be rewarded in the context of deferring business-as-usual network upgrades.

1.5 Terminology

The terms 'Intelligent Grid' and 'Smart Grid' have become increasingly used over the past few years and care needs to be taken to clearly define them. For the purposes of this research program, an 'Intelligent Grid' is an electricity network that uses 'Decentralised Energy' resources and advanced communication and control technologies to deliver electricity more cost-effectively, with less greenhouse gas emissions than the current electricity supply mix, while being responsive to consumer needs.

In this context, as alluded to above the term 'Decentralised Energy' ('DE') means electricity generation and management of energy use applied at the consumer or distribution network level. (Note that related Intelligent Grid research projects have in the past referred to 'Distributed Energy' in a manner that is synonymous with this term 'Decentralised Energy' – the concept and key elements remain unchanged). DE includes the three key elements of distributed generation, load management and energy efficiency options. 'Distributed generation' refers to an array of technologies and can include wind turbines (but not those connected to the high voltage transmission network), solar panels, micro turbines, fuel cells and co- or tri-generation (also known as 'combined heat and power'). 'Load management' refers to the management of critical loads at peak times on the distribution and transmission networks through measures such as load shifting (performing non-essential energy using tasks at different time), standby generation, or time of use pricing incentives. 'Energy efficiency' refers to utilizing equipment or implementing behaviours that can achieve the same outcome with less energy input.

These types of energy resources can generally be located closer to energy users than large centralised sources. Some Decentralised Energy resources rely on renewable energy with no greenhouse emissions and others make more efficient use of fossil fuels. For example, the application of Decentralised Energy resources could involve heating, cooling and powering a commercial building using a combination of solar panels, fuel cells, energy efficiency and load control.

When Decentralised Energy is used within the framework of electricity network planning to alleviate impending constraints, this can be termed 'Demand Management'. Therefore the terms Demand Management (DM) and Decentralised Energy (DE) are used interchangeably for the purposes of this research (given its focus on alleviating network constraints). A network constraint refers to a critical peak period on the network where the maximum capacity of the network to supply power is reached, or exceeds an acceptable level of risk, which under standard practices then requires augmentation of network to alleviate that risk of power outage.

2 Electricity network investment

2.1 Australia

Australia's electricity network infrastructure is currently undergoing a dramatic increase in the level of capital investment relative to previous decades. Analysis of each jurisdiction reveals that in the most recent five-year regulatory periods (to 2014 or 2015), capital expenditure in electricity transmission and distribution networks is expected to total more than $47 billion[4] across the nation, or more than $9 billion per year. Given the magnitude of this investment and the implications for consumer electricity prices, this investment has received little media attention, relative to the National Broadband Network for example, which involves a substantially smaller sum of money. This is partly because approvals of network spending for a 5-year period are handed down by on a state-by-state basis over a period of several years by an independent regulatory body, the Australian Energy Regulator (AER). Essentially for each 5-year regulatory period every network business submits its estimate of how much it will need to invest in its network over the coming five years to meet its licence conditions to maintain a safe and reliable network. Almost exclusively utilities take a business-as-usual approach that favours network solutions. The AER then tells each network how much of that estimate it considers to be an "efficient" level of spending; generally reducing proposed expenditure by some margin. The network then recovers these costs through electricity tariffs over a period of approximately 40 years.

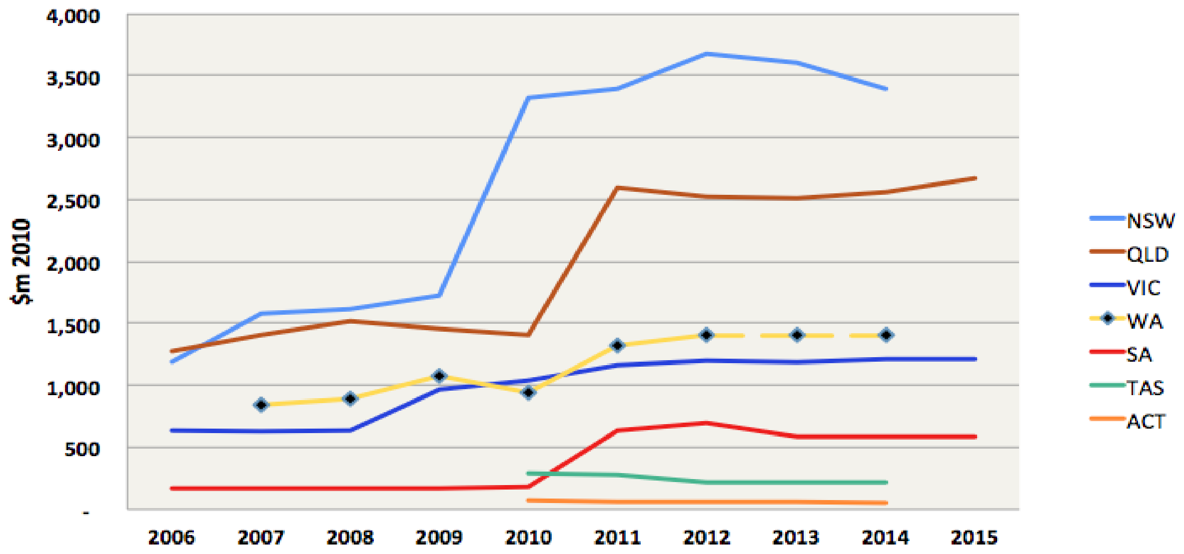
Figure 2 below shows the regulator-approved network capital expenditure in each jurisdiction for the past two regulatory periods, from 2005-06 up to 2014-2015.[5] Note the dramatic rise in investment in the second regulatory period, particularly in NSW and Queensland. Figure 2 does not show that this escalation was in fact on top of earlier spending increases of approximately 180 per cent on the period 2001-2005 in the case of NSW and Queensland (Simshauser *et al.* 2010).

In Victoria, a lower but significant proportional jump in investment occurred of over 50 percent between the two regulatory periods, from $3.9 billion in 2006-2010 to $6.0 billion in 2011-2015.

[4] In $2010 AUD.

[5] Each jurisdiction runs on a slightly different regulatory cycle.

Figure 2: Electricity Network Capital Expenditure (T&D) by Jurisdiction, 2006-2015



Data sources: AER and other regulator decisions (see sources for Table 1); Insufficient data available for NT

Table 1 shows the overall breakdown of the $47 billion by jurisdiction. NSW and Queensland together account for over 60 percent of the total network capital expenditure, while Victoria accounts for 12.6 percent.

Table 1: Electricity network capex by jurisdiction, most recent 5-yr determinations (converted to $2010 million AUD)

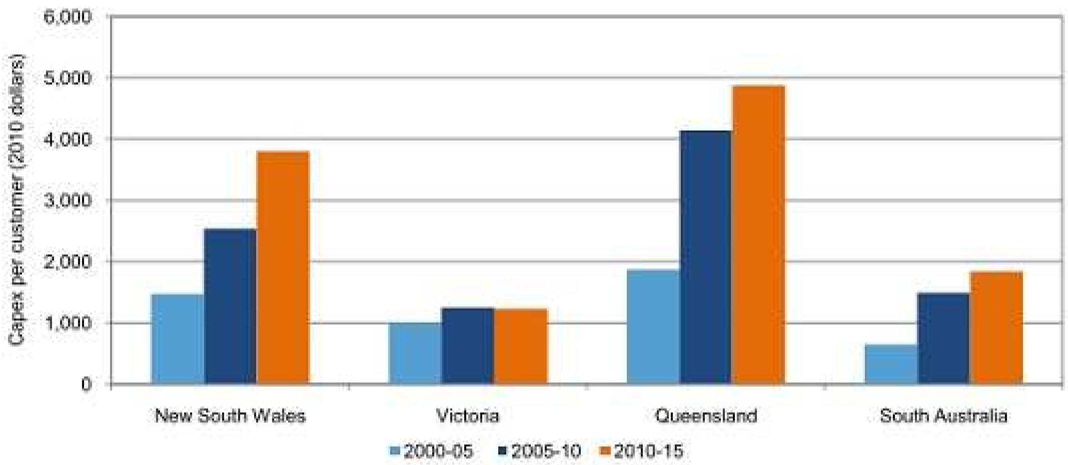
	2010	2011	2012	2013	2014	2015	5-Yr Period
NSW[1]	3,323	3,397	3,674	3,608	3,393	-	17,394
Qld[2]	-	2,602	2,521	2,516	2,563	2,674	12,877
Vic[3]	-	1,163	1,201	1,187	1,215	1,210	5,976
SA[4]	-	635	700	580	581	580	3,076
Tas[5]	285	279	211	216	216	-	1,208
ACT[6]	65	60	58	52*	49*	-	284
WA[7]	947	1,323	1,402	1,402#	1,402#	-	6,476
TOTAL	4,620	9,458	9,767	9,562	9,419	4,464	47,290

Notes:
Table sourced from Intelligent Grid Working Paper 4.4 (in press)
** Simple extrapolation of last approved year of transmission and distribution capex.*
 # Simple extrapolation of last approved year of distribution capex (transmission is as approved to 2014).
Data Sources:
1. AER, NSW distribution determination 2009-10 to 2013-14 (Final decision, 28 April 2009),Tables 7.16, 7.17 & 7.18; AER, Transgrid Draft Transmission determination 2009–10 to 2013–14, Table 2.
2. AER, QLD distribution determination 2010-11 to 2014-5 (Final decision, May 2010), Tables 7.21 & 7.22; AER Decision—Queensland transmission network revenue cap 2007–08 to 2011–12, Table 3.4.
3. AER, Victorian electricity distribution network service providers distribution determination 2011–2015 (Final decision, October 2010), Tables 5.25-5.27; AER, SP AusNet transmission determination 2008-09 to 2013-14 (Final Decision, January 2008), Table 4.27.
4. AER, South Australia distribution determination 2010-11 to 2014-5 (Final decision), May 2010, Table 7.8; AER, ElectraNet transmission determination 2008–09 to 2012–13, 11 April 2008, Includes Includes ex ante capex (Table 3.19) + conditionally approved contingent project costs (Table 3.18).

5. Office of the Tasmanian Energy Regulator, Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania Final Report and Proposed Maximum Prices September 2007, Table 4.11; AER, Transend Transmission Determination 2009–10 to 2013–14, 28 April 2009, Transend, Table 4.12.
6. AER, ACT Final Determination 2009-10-2013-4, Table 8.11. To avoid double counting TransGrid expenditure was not included in the above table for ACT.
7. Economic Regulation Authority, Further Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network, 19 January 2010, Table 3.

It is interesting to interpret the above jurisdictional network capital expenditure data on a per customer basis. Victoria is the only state shown in Figure 3 that did not to observe a significant rise in network capital expenditure on a per customer basis in the past two regulatory decisions. The reasons for this are not currently clear, although it does not appear to relate to lower levels of peak demand growth (see discussion in Section 2.3). It is possible that this effect most strongly flows from Victoria's probabilistic network reliability and planning standards, as opposed to the deterministic methods used in other jurisdictions, which when combined with Government push for higher reliability and the limited mandate of the AER to question network spending, can result in overinvestment in electricity networks.

Figure 3: Electricity network capital expenditure per customer by regulatory period



Source: Energy Users Association of Australia in Parkinson (2011).

2.2 Victoria

As seen above, Victorian NSPs, in the most recent Final Determination from the AER for the period 2011-2015, had approved a significant overall aggregate rise in total capital expenditure relative to the previous regulatory period 2006-2010. However, this approved expenditure was a substantial margin lower than that applied for by the Distribution NSPs (DNSPs) in their original regulatory proposals,[6] and also far lower in total than the approved expenditure for the other eastern seaboard states. The AER's Final Determination approved

[6] Available from: <http://www.aer.gov.au/content/index.phtml/itemId/732540>

a 14 percent reduction in total capital expenditure originally proposed by Victorian DNSPs, including a 21 percent reduction in peak demand growth related network expenditure (discussed in more detail in the subsequent section).

Table 2 shows the breakdown of expenditure by Network Service Provider, which suggests that well over half of all distribution network capital investment in Victoria is in regional areas (SP Ausnet and Powercor).

Table 2: Electricity network capex by DNSP, 2011-2015 ($2010 million AUD)

Network	2011	2012	2013	2014	2015	5yr Total
UED	193	198	172	161	162	887
Jemena	85	97	97	102	93	473
SP Ausnet	292	298	305	295	291	1,481
Citipower	155	157	172	172	174	830
Powercor	298	303	311	326	330	1,567
Distribution total	**1,023**	**1,052**	**1,057**	**1,056**	**1,051**	**5,239**
SPA (Transmission)	140	148	130	159	159	737
Total	**1,163**	**1,201**	**1,187**	**1,215**	**1,210**	**5,976**

Sources: AER, Victorian electricity distribution network service providers distribution determination 2011–2015 (Final decision, October 2010); AER, SP AusNet transmission determination 2008-09 to 2013-14 (Final Decision, January 2008), Table 4.27.

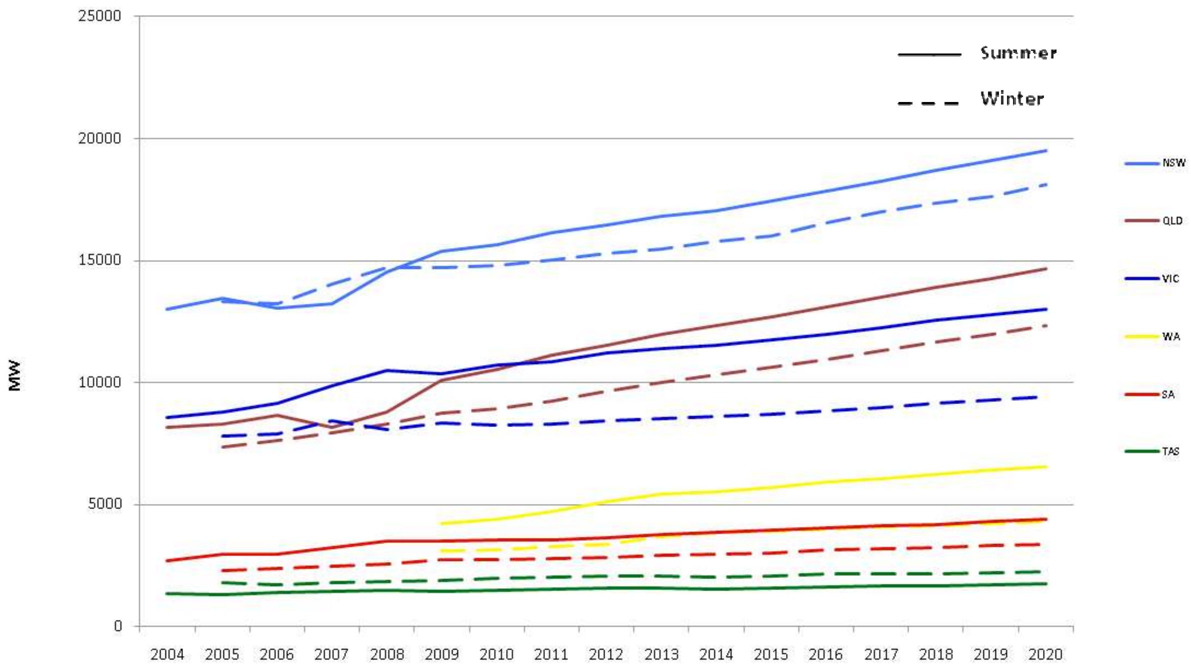
2.3 Peak demand growth & network investment

The three primary drivers of this capital expenditure on network infrastructure are:

- Ageing infrastructure replacement, as many network assets around the country are reaching the end of their operating lives;
- Strong growth in peak demand; and
- Increased reliability standards imposed by governments on electricity utilities (although this driver does not currently apply to Victoria).

The focus of this work is on peak demand, as this investment is considered potentially avoidable if demand growth can be moderated. Peak demand refers to the single highest instantaneous use of electricity during the course of a year, and is shown by jurisdiction in Figure 4. Peaks generally occur on hot or cold weather days, when consumers have high usage of electricity for space heating and cooling in buildings. In recent years strong growth in the uptake of air conditioning in different building sectors has led to higher summer relative to winter peak demand in most jurisdictions. This summer peak dominance is most pronounced in Victoria (the difference between the navy blue dashed and solid lines), thought to be largely due to the relatively higher penetration of gas for winter heating applications (Langham *et al.* 2010).

Figure 4: Electricity Peak Demand Forecast to 2020 by Jurisdiction



Sources: 2009 AEMO Electricity Statement of Opportunities (NSW,QLD,VIC,SA,TAS) and WA Independent Market Operator 2009 (WA - SWIS only), NT not included due to data availability. All based on 10% Probability of Exceedance.

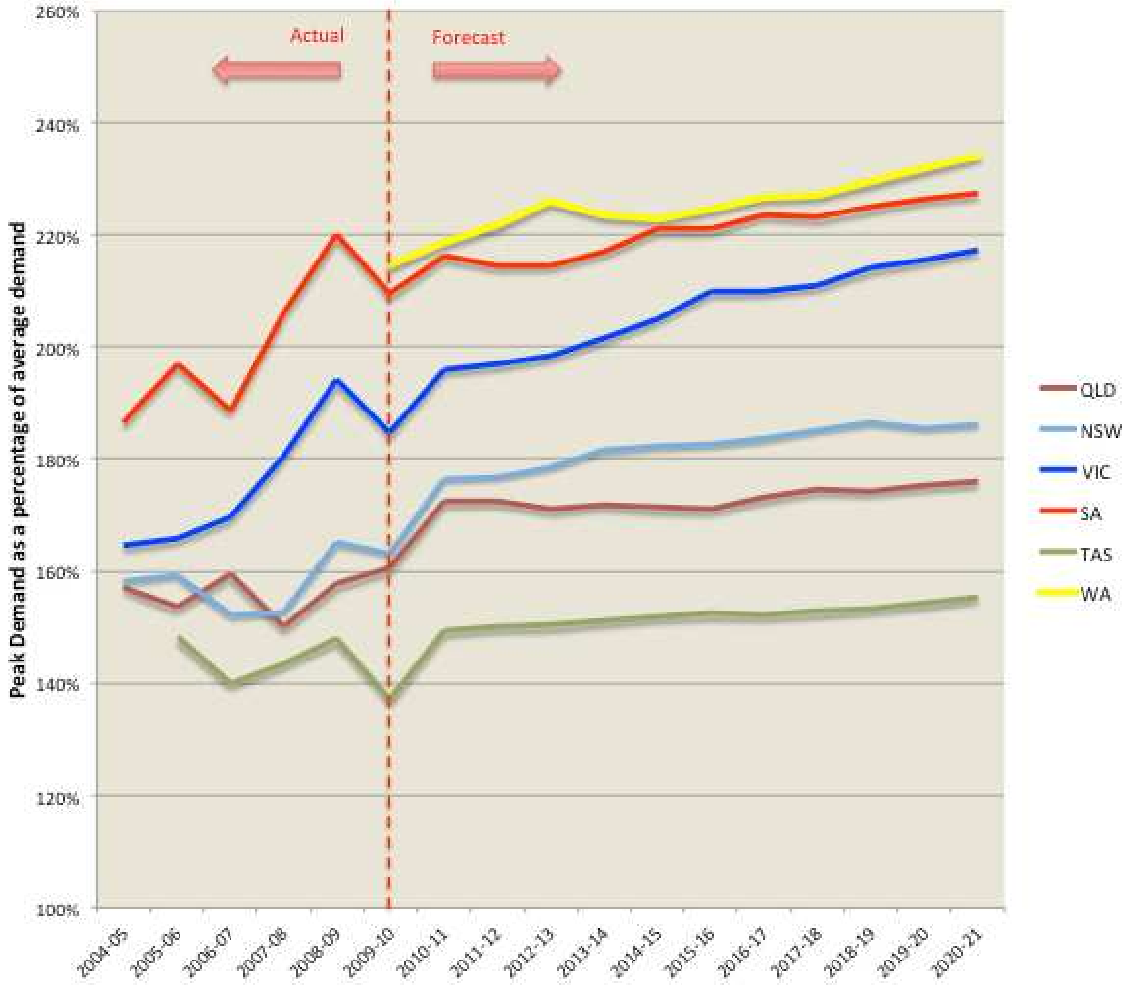
To avoid power outages, the capacity of generation and distribution systems must supply sufficient power to meet peak demand at any given instant. Therefore it is the peak electricity demand that determines the required size of cables and substations servicing a particular area, and is the major reason for the need to increase capacity at ‘bottle necks’ in the system.

Core to the increasing costs associated with delivering every unit of energy to consumers, is the increasing ‘peakiness’ of electricity demand. Out to 2020, Victoria’s peak demand (in megawatts; MW) is forecast to increase at double the rate of total electricity demand (in megawatt hours; MWh) (AEMO 2009).

The higher the peak demand relative to total demand, the more infrastructure capacity will be required to deliver that electricity. This means that higher relative peak demand results in every unit of electricity delivered from centralised power stations to end users being more infrastructure intensive, and therefore more expensive in terms of capital investment. The key illustration of the forecast trend in the relationship between peak and total demand in Victoria is shown in Figure 5. These figures are derived by dividing the average demand (the theoretical demand if all energy consumption was spread evenly across every hour of the year) by the absolute peak demand to obtain a percentage.[7] Since 2004, Victoria has seen a significant increase in the relative magnitude of its peak, increasing from 165 to 185% of average demand. This represents a decline in network load factors or capital efficiency of more than 1 percent per annum. The trend of worsening network capital efficiency is forecast to continue out to 2020, reaching a peak load of almost 220% of average demand, approaching the poor load factors of states such as South Australia and Western Australia.

This indicates that the observed trend of increasing investment in growth-related infrastructure is expected to continue strongly for the foreseeable future, continuing to place strong upward pressure on electricity prices.

Figure 5: Actual and Forecast Peak Demand as a Proportion of Average Demand by State, 2004-05 to 2020-21



[7] This is the inverse of the concept of "network load factors", which is a measure of how efficiently the network is being utilised. A declining load factor means poorer efficiency.

Data source: AEMO and WA Independent Market Operator 2009 Statement of Opportunities documents. Based on summer peak demand at 10% Probability of Exceedance (POE).

Figure 4 and Figure 5 together support the suggestion that Victoria's lower level of network investment is **not** related to a lower rate of peak demand growth, nor a less peaky demand. In fact, the trend is quite the opposite.

Thus it appears that either Victoria can expect to face a dramatic increase in network investment in the 2016-2020 regulatory period, or potentially other States are 'over investing' in network infrastructure while Victoria has managed to maintain relative prudence and efficiency in its network infrastructure investment processes, despite the similarity of regulatory approval processes between jurisdictions.

3 Calculating avoidable network investment

3.1 Avoidable network costs and the role of decentralised energy

At present, the Australian electricity sector typically addresses anticipated growth in peak demand by increasing centralised generation capacity and by investing in transmission and distribution capital to increase the carrying capacity of the network. However, Decentralised Energy (DE) can provide alternatives by reducing demand or increasing generation close to the source of demand. However DE can generally only achieve this cost-effectively if applied as demand management (DM) to *defer* or *avoid* the building of *new infrastructure*.

This section considers the specific components of network investment that are likely to be 'avoidable' or 'deferrable' for this purpose.

3.1.1 Avoiding or deferring network investment?

The distinction between 'deferral' and 'avoidance' of infrastructure investment lies essentially in the period of time an investment is delayed. For example, if there is an impending growth-driven network constraint that would require a $10 million network solution to alleviate, a moderate amount of DM may be available that can reduce the rate of underlying growth, and *defer* the need for that investment for say, two years. If a larger amount of DM was available relative to the underlying growth rate, no reinforcement of the network may be required. This situation is what would be termed 'avoidance', but is in practice no different to prolonged deferral of network infrastructure.

The vision of the Intelligent Grid research program is for DE to be implemented effectively and at large scale into the future, slowing and ultimately eliminating net growth in electricity consumption and peak demand. In this case we would see short-term deferral initially, and long-term avoidance of network infrastructure.

In this paper, we will refer to the economic value associated with deferring network investment for one year as the "annual deferral value" or the *"avoidable network cost"*. Put differently, the *annual deferral value* reflects the opportunity cost associated with failing to implement DE measures.

3.1.2 Defining Avoidable Network Costs

Not all network capex is avoidable. As mentioned earlier, Australia's $47 billion and Victoria's $6 billion of network capex over the current five-year period includes investments associated with a range of drivers. The Dynamic Avoidable Network Cost Evaluation (DANCE) Model has been developed to identify avoidable network capex and to map these potentially avoidable costs in space and time. In the context of the application of DE or 'non-network' options for the purposes of the DANCE Model, avoidable capex costs are considered to be only those investments that are undertaken in response to growing peak demand. In regulatory terms this investment is commonly classified as 'network augmentations', or 'reinforcements' in the case of Victoria. For a more detailed discussion of types of investment and what is classed as avoidable, see the Intelligent Grid DANCE Working Paper 4.4 (Langham et al, 2011).

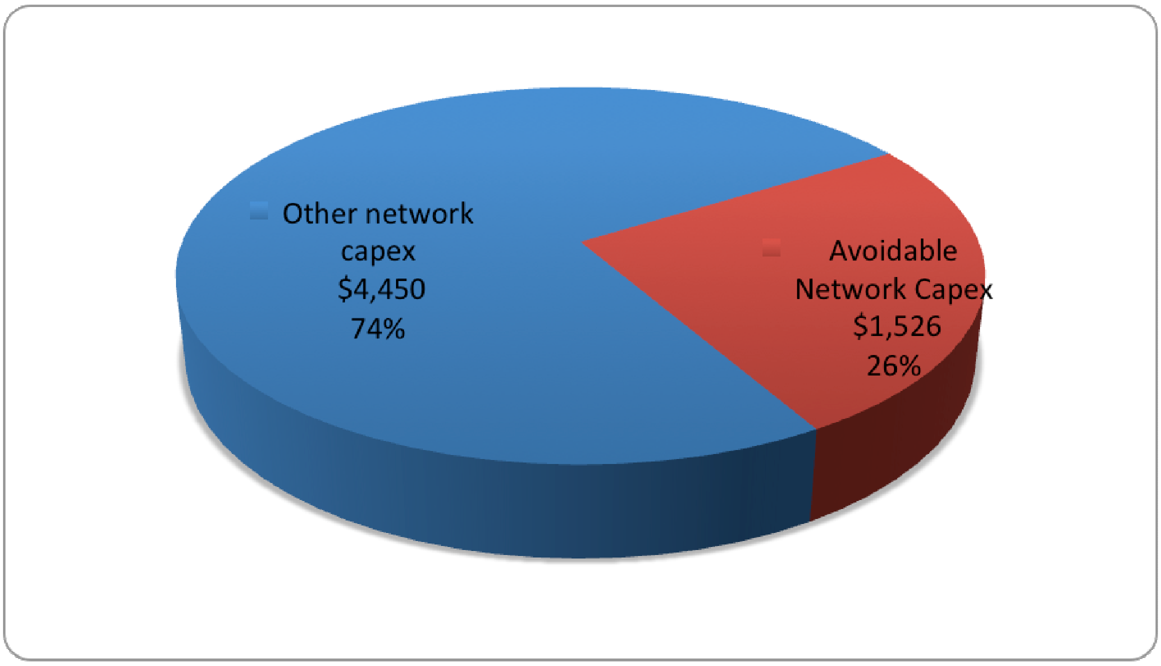
It is worth noting that network operating expenditure (opex) would also be directly avoided by eliminating the need to maintain new additional network infrastructure caused by demand growth, the Net Present Value of which has been calculated to be in the order of a further 20 to 25 per cent of the annual deferral value of capital expenditure (Langham *et al.* 2010). This is not quantified as part of the DANCE Model as it deals strictly with upfront capital expenditure.

3.2 Quantifying Victoria's avoidable network costs

To determine the magnitude of avoidable network costs in Victoria, a detailed review and analysis of publicly available transmission and distribution network business regulatory documents was undertaken to record the total value of 'network reinforcements'.

The results of this analysis are shown in Figure 6 below, with avoidable network capex (red wedge) making up around 26 percent of all projected network capex over the current five-year regulatory period. Victoria's avoidable proportion is substantially lower than the national figure, which is estimated at 32 percent of total capex (Langham and Dunstan 2011).

Figure 6: Victorian total and avoidable network capex 2010-2015 ($m 2010)



Victoria's avoidable network costs total just over $1.5 billion dollars over the next five years if demand growth was to be eliminated over this period. Table 3 below shows a breakdown of this $1.5 billion by network service provider, and considers this growth-related investment alongside the peak demand growth over that period in order to derive a figure for growth capex cost per MW. It suggests that every additional MW of peak demand costs Victorian consumers $1.10 million.

Table 3: Network reinforcement capex per unit peak demand growth

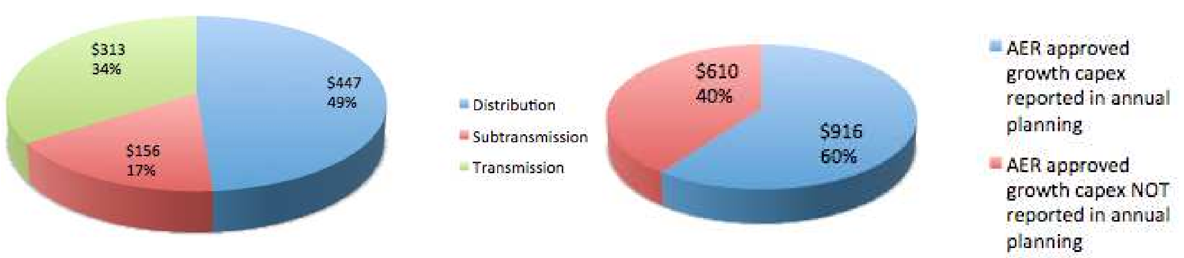
	Network reinforcement capex ($m 2010)		Peak demand growth (MW)		Growth Capex per MW
Network business	5yr Reg. Period	Per annum	5yr Reg. Period	Per annum	($m/MW)
UED	$181	$36	232	58	$0.62
Jemena	$99	$20	113	28	$0.70
SP Ausnet	$389	$78	345	86	$0.90
Citipower	$268	$54	167	42	$1.28
Powercor	$277	$55	367	92	$0.60
Distribution Total	**$1,213**	**$243**	**1,224**	**306**	**$0.79**
SP Ausnet (transmission)	$313	$63	817	204	$0.31
Total	**$1,526**	**$306**			**$1.10**

Data Sources: Distribution data from AER 2010; Transmission investment data from Joint DB Transmission Planning Connection Report (Citipower et al. 2010, pp.5-10); Transmission demand growth from VENCORP, Annual Planning Report 2009, Table 3-3.

The $/MW distribution figures presented in Table 3 represent a 60 percent increase on the past regulatory determination for Victoria, but are still dramatically lower than figures for most other Australian jurisdictions (Langham *et al.* 2010).

Further analysis of this data reveals that around half of the investment is at the distribution zone substation level, one third at the transmission level, and the remainder at the sub-transmission level (Figure 7, left). When this growth-related investment in the annual planning reports is tabulated and cross-referenced against the growth-related expenditure approved by the AER shown in Figure 6, it is found that only 60 percent is accounted for, while the remaining 40 percent is not reported (Figure 7, right). It is not clear where the remaining $610 million would be spent, but may (at least in part) be explained by additional network expenditure below the Distribution Zone Substation level.

Figure 7: (Left) Breakdown of network investment by type, as reported in Annual Planning Reports; and (Right) Reported vs Unreported Growth-related Network Expenditure ($m)



Data Source: Distribution and Transmission Annual Planning Reports

3.3 Quantifying annual deferral value

The central thesis behind this research on network investment, is that if even a portion of the $1.5 billion shown in Figure 6 above was redirected towards efficient DM measures, substantial economic and greenhouse gas emission savings could be achieved relative to the business-as-usual approach. To determine the value below which DM can be applied cost effectively (or “efficiently” in regulatory terms), it is possible to calculate the “annual deferral value”. This represents the amount of money that the network business would save on an annual basis if it did not need to implement its preferred business-as-usual network solution to a capacity constraint. This can be used as a proxy for the maximum value that society should be willing to pay for the implementation of DM if the same reliability and service criteria are met.

The annual deferral value is derived by ‘annualising‘ the marginal cost of each additional kW of capacity that could potentially be avoided through utilisation of decentralised energy if the constraint can be avoided. The ‘simple’ version of the per unit growth network investment figures is presented in Table 3 above. To obtain the annual deferral value the methodology developed by Langham et al. (2010) was applied, whereby data from Table 3 was used to calculate *seasonal* growth metrics using the following steps:

- **Step 1**: Distribution – the dominant peak season for each substation of Victoria’s network businesses were tallied and the proportional seasonal breakdown was recorded based on projected demand in the last forecast year (generally 2014). That is, if Powercor was to have 100 substations, 91 of which have a higher summer peak in 2014, a 91:9 summer:winter split was recorded.[8] The total growth related capex over the 5-year regulatory period (2011-15) for each network business was then multiplied by the summer/winter split to produce a figure for seasonally-specific growth capex. This means that for all avoided infrastructure costs to be tallied; summer and winter metrics must be added together.

- **Step 2**: Transmission – as Victoria has a clearly dominant summer peak season, a simplifying assumption was made that all planned transmission investment is assigned to the dominant peak season. This meant that 100% of transmission expenditure assigned to the summer peak. While this may not always be strictly correct, limited data was available to warrant alternative assumptions.

- **Step 3:** Demand growth scaling – data on the seasonal growth is seldom reported at an aggregated network level. For this reason, the network provided growth figures (in MW) were scaled based on Victoria’s peak demand according to AEMO (2009). For both distribution and transmission 100% of the total reported peak demand growth

[8] The more detailed DANCE research revealed no winter peaking zone substations in the urban regions of Melbourne therefore UED, Jemena and Citipower were all noted as 100% summer. In the relatively limited number of cases where loads were equal, summer was recorded as the peak season. Where not all substations’ forecast demand were reported, the subset of “constrained” substations was used.

was allocated to summer, the dominant peak season. Winter was then scaled as a proportion of the dominant season according to project growth to 2020. In Victoria the total winter peak growth was found to be 42% of the total summer peak growth, which was used as the scaling factor for the demand growth reported by the network. Final seasonal metrics were then calculated by dividing the seasonal network capex by the scaled seasonal demand growth (to give a $m/MW metric).

The 'annualised' value of combined seasonal growth metrics of $1.21m/MW ($1.02m/MW for summer and $0.19m/MW for winter), was then calculated using:

- A real 'vanilla' Weighted Average Cost of Capital (WACC) of around 7% per annum,[9] as the need to service loans on network capital is eliminated if network infrastructure spending is deferred; and
- Avoided depreciation of 2.5% per annum, reflecting a straight-line depreciation over a typical 40-year lifespan of network infrastructure.

This method results in an annualised value of 9.5 per cent of the total capital cost. This means that in Victoria the average planned network reinforcement is worth in the order of $115/kVA/yr for each year sufficient DM can be employed to defer that investment. The actual value of network deferral varies greatly, however, depending on the specific point within the network. The DANCE Modelling highlights where this variation occurs temporally and spatially.

[9] Based on nominal vanilla WACC of 9.54% (average of all Victorian DNSPs in AER 2010) adjusted for inflation of 2.57%. (AER 2010)

4 Locating Avoidable Network Investment

4.1 Introduction to the DANCE Model

The augmentation investment and demand growth data, upon which the annual deferral values presented in Section 3.3 are based, stem from the distribution zone substation, sub-transmission and transmission terminal station level. The figures presented in Table 4 above have been averaged across whole jurisdictions and in the case of the national average, across the country. While these are useful for high-level analysis of the overall potential for the assessment of avoidable network costs from DE, they inherently “obscure” the spatial and temporal variability of investment in network infrastructure.

The smaller the area of interest, the less applicable these particular average values will be. In many substation zones the avoidable infrastructure value will be zero as there is no planned growth investment, while in others the value will be many times these averages. To properly assess the avoidable network costs in a specific geographical area requires knowledge of the planned growth-related investment in the specific infrastructure servicing that area, and the amount of peak demand savings required in any given year that is required to defer that investment.

This is the role that the DANCE Model plays, by building an economic model and mapping outputs directly from the primary zone substation level data, enabling the highlighting of ‘value hotspots’ in time and space where Decentralised Energy resources can be applied most cost-effectively by deferring network investment.

4.2 Purpose and audience

The purpose of the Dynamic Avoidable Network Cost Evaluation (DANCE) Model is:

> *To quantify and map the spatial and temporal variation in avoidable network costs in order to identify where within the network DE should be targeted for the greatest value.*

In producing the investment analysis and visual output tools DANCE seeks to assist the following stakeholders to better engage with the potential of DE:

- Distribution network businesses;
- Policy makers; and
- DE service providers.

It is intended that DANCE assist **distribution network businesses** by complementing their existing planning and management tools for the assessment of non-network options. Perhaps more importantly, by taking network planning data that is currently poorly understood by those unfamiliar with it, DANCE aims – through creating simple but powerful interactive visual outputs – to make this information more accessible. This will help **policy makers and regulators** to understand the dynamics of where and how DM can contribute to beneficial economic and environmental outcomes, and **DE service providers** who wish to know the geographical areas in which to look to achieve the greatest benefit from their products. This makes DANCE a potentially valuable communication tool for network businesses in looking to engage with demand side participants.

4.3 Inputs

The DANCE Model aims to use the simplest inputs possible to reconstruct (with reasonable accuracy) complex variations in electrical demand throughout the year, to enable calculation of the avoidable costs of electricity network investment over time and space. The inputs are as follows:

- Substation-level electricity demand data:
    - Current year plus 5-year summer and winter peak demand forecast in MVA for each Distribution Zone Substation, Sub-Transmission Feeder Line/Loop and Terminal Station (12 data points per asset); and
    - Hourly load curve shapes for the peak and a representative average weekday during summer and winter, and for a representative average weekday during spring/autumn (5 x 24 data points per asset); and[10]
    - The observed peak for each month of the year (12 data points per asset); *OR*
    - Observed/modelled 8760 hourly demand (8760 data points per distribution substation – only used if readily available from the network business)
- Network capacity information:
    - Secure capacity in MVA in summer and winter (2 data points per asset).
    - The name of the sub-transmission loop and Terminal Station serving each Distribution Zone Substation (2 data points per distribution zone substation).
- Geographic information:
    - Geographic coordinates for each substation (2 data points per distribution zone and substation).
- Investment information:
    - Proposed value of preferred network solution for all substations facing a growth-related constraint (1 data point for each asset where investment is planned).
    - Proposed year of augmentation investment (1 data point for each asset where investment is planned).
    - The above investment data is based on the amounts that are publicly reported in annual planning documents. For distribution and sub-transmission, this is for the period 2011-2015, and for transmission is for the period 2011-2020.

For this Victorian study, the three primary data sources for the above information were:

[10] For any substations for which load curve shapes, monthly peaks or 8760 hourly data was not available, peak day summer and winter load curve shapes for the upstream Terminal Station, and relative monthly peak magnitudes of the Victorian NEM data were used as proxies.

1. December 2010 Distribution System Planning Reports (DSPRs) (Citipower, 2010; Powercor, 2010; Jemena, 2010, SP Ausnet, 2010, United Energy Distribution, 2010) and Transmission Connection Planning Report (Citipower et al. 2010);
2. AEMO Transmission Terminal Station summer and winter load curves (AEMO Transmission Services, 2010); and
3. Non-publicly available distribution zone substation load data provided directly by Citipower-Powercor, Jemena and United Energy Distribution.

In addition to the above data inputs for each substation, there are also economic variables that carry default values, but are user-controlled. These are:

- Weighted Average Cost of Capital (WACC) – a figure of 7% per annum 'real vanilla WACC' is used for the Victorian analysis, which was calculated by averaging AER's Victorian Final Regulatory Decision (AER 2010a) nominal vanilla WACC for all network businesses and subtracting the inflation rate.
- Depreciation value of network assets – the default of 2.5% is calculated as a straight-line depreciation over a 40-year infrastructure lifetime.
- Discount rate – the default value is 7% based on NSW Government (2007).

4.4 Calculation Method

For full detail on the DANCE Model calculation method please refer to Intelligent Grid Working Paper 4.4 (Langham et al, 2011). This section provides an overview of the major calculation to turn demand growth forecasts and network investment information into avoidable network costs (marginal deferral values), as well as highlighting any data inputs specific to the Victorian context.

4.4.1 Annual deferral value

Using basic annual peak demand forecast data, the DANCE Model calculates the **annual demand growth rate** for each substation, and using the **proposed investment data** calculates the summer and winter Long Run Marginal Cost (LRMC) in $/kVA/yr for each of the "forecast years", using the following formula:

$$LRMC_{(Forecast\ yr)} = \frac{Augmentation\ Cost\ [\$m] \times 1000 \times (WACC\ [\%\ p.a.] + Depreciation\ [\%\ p.a.]) \div Avg\ Ann.Growth\ [MVA/yr]}{(1 + Discount\ rate\ [\%\ p.a.])^{(Investment\ yr - Forecast\ yr)}}$$

Average annual growth in the above formula is calculated from the current year up until the year of proposed investment.[11] The LRMC of distribution is calculated separately from the LRMC of sub-transmission for both summer and winter, and these values are then added together to get a total LRMC in the "effective peak season". This is because a distribution substation might be winter peaking, while the sub-transmission asset might be summer

[11] In the case where the current year is *also* the proposed year of investment, average annual growth rate is calculated as the growth rate between the current year and the subsequent year.

peaking, but the same kind of DM may not be effective in relieving both constraint types. The effective peak season is calculated in DANCE as the season (summer/winter) in which the greatest shortfall of capacity occurs in the final forecast year. This definition is used to distinguish some constraints that occur in both summer and winter at a particular substation. Some care is required in this assessment, however, as there are some unusual load situations that warrant the overriding of the automatic classification of effective peak season. While in Victoria almost all network assets are summer peaking (with the exception of a few),[12] there are several that face dual constraints. While the winter peak growth rate is generally less than the summer growth rate and thus summer is the primary constraint season, the additional information category “Constraint = BOTH” included with the annual deferral value images is included to show where both summer and winter may be relevant from a Demand Management perspective. The outputs of this initial basic annual LRMC calculation are shown later in Figure 14.

To step through the annual deferral value calculation process, it is useful to take a case study of a given distribution zone substation. An example of Flinders Ramsden (FR) Zone Substation is taken, with the steps involved in calculating the annual deferral value are highlighted in Table 4 below, showing the separate calculation of distribution, sub-transmission and transmission deferral values after factoring in investment values and annual load growth.

Table 4: Case study – Annual deferral value at Flinders Ramsden (FR) Zone Substation in 2012

Proposed Investment (Distribution):	No investment planned by 2015
Distribution Annual Deferral Value ($/kVA/yr)	$0/kVA/yr (1)
Proposed Investment (Sub-transmission) **Sub-transmission Annual Deferral Value ($/yr)** **Sub-transmission Annual Load Growth** **Sub-transmission Annual deferral value discounted back to 2010 ($/kVA/yr)**	$18 million (planned for 2013) 9.5%[13] x $18m = $1.71m/yr discounted back to 2012 @ 7% p.a. discount rate = $1.6m/yr 2,300 kVA $694/kVA/yr (2)

[12] This may seem somewhat counter-intuitive given that NSW has a warmer climate yet numerous winter peaking substations, the primary reason for this is that Victoria has a high penetration of gas for domestic space heating in winter, and thus summer air conditioning is the primary load on the electrical system.

[13] Weighted Average Cost of Capital (WACC) of 7% plus avoided straight-line depreciation of 2.5%, as detailed in Section 3.3.

Proposed Investment (Transmission)	$170 million (planned for 2014)
Transmission Annual Load Growth	46,200 kVA
Transmission Annual deferral value discounted back to 2010 ($/kVA/yr)	$305/kVA/yr (3)
Total Annual Deferral Value (Distr'n + Subtra'n + Trans'n)	**$999/kVA/yr (1+2+3)**

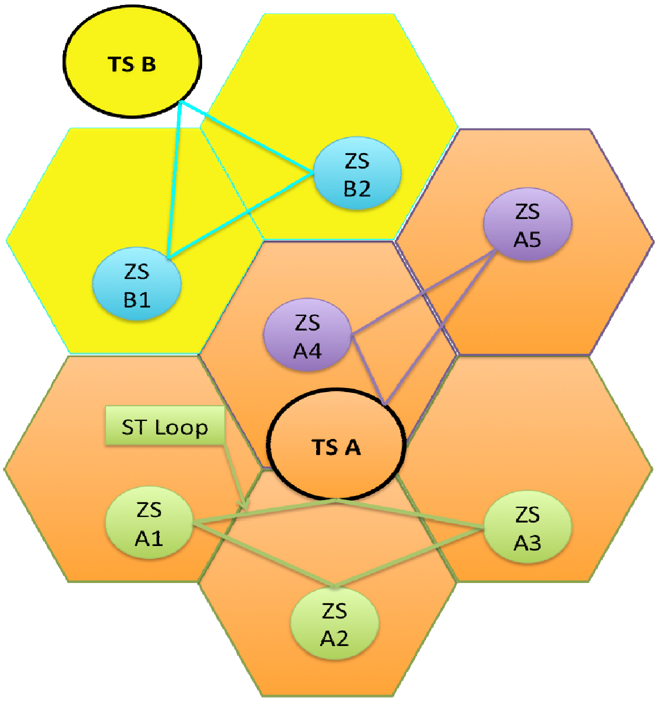
Figure 8 demonstrates graphically how the assignment of the three levels of investment analysis shown in Table 4 is conducted. The DANCE Model map outputs show deferral values at the distribution zone substation feeder region level, which are represented by the hexagonal shapes in Figure 8. A hierarchy of network assets supplies each feeder region (hexagon): at the lowest level each feeder region is supplied by a distribution Zone Substation (ZS);[14] at the highest level of this analysis each ZS is supplied by a transmission Terminal Station (TS); and in the middle, each ZS is supplied by a sub-transmission line/loop that connects the ZS to the TS. The following examples illustrate how these levels relate in Figure 8:

- Investment at the transmission level at **Terminal Station A (TS A, in orange)** will result in a deferral value that relates to the amount of investment, and the load conditions at that specific TS. This transmission deferral value will be passed on to all of the orange feeder regions (hexagons). Likewise investment at TS B will only pass on deferral values to yellow regions.
- Investment at the sub-transmission level, at the **Green Sub-transmission loop,** will result in a deferral value that relates to the amount of investment, and the load conditions on that specific loop. This sub-transmission deferral value will be passed on to any region connected to TS A by the green ST Loop (those orange hexagons with green borders – ZS A1, A2 and A3).
- Investment at the distribution level, at **Zone Substation (ZS) A1 in green,** will result in a deferral value that relates to the amount of investment, and the load conditions at that ZS. This distribution deferral value will only apply to the region within which it is located.[15]

[14] There are also distribution substations below the level of the Zone Substation, however the analysis does not go to this level of granularity due as the Zone Substation is the spatial scale at which the load and investment data is publicly reported.

[15] In reality Zone Substations are not always physically within the feeder region they service, and thus some ZS points in the DANCE Maps (blue dots) were shifted slightly to ensure that deferral values were correctly passed on to the appropriate region.

Figure 8: Illustration of assignment of distribution, sub-transmission and transmission deferral values



4.4.2 Hourly deferral value

In order to calculate the hourly deferral value across a given day, it is necessary to determine for how many hours per year that demand occurs. This information is available from the Load Duration Curve and is used to convert the annual deferral value associated with a particular constraint to a value per unit of energy delivered. This is demonstrated through the following formula:

$$Hourly\ Deferral\ Value_{(Time\ of\ Day)} = \frac{Annual\ Deferral\ Value_{(For\ specific\ substation)}}{Annual\ Hours\ of\ Occurrence_{(Demand\ @\ Time\ of\ Day)}}$$

This can be explained mathematically in terms of the units:

$$Hourly\ Deferral\ Value_{(Time\ of\ Day)} = \frac{\$/kVA}{yr} \div \frac{hrs}{yr} = \frac{\$/kVA}{\cancel{yr}} \times \frac{\cancel{yr}}{hrs} = \$/kWh$$

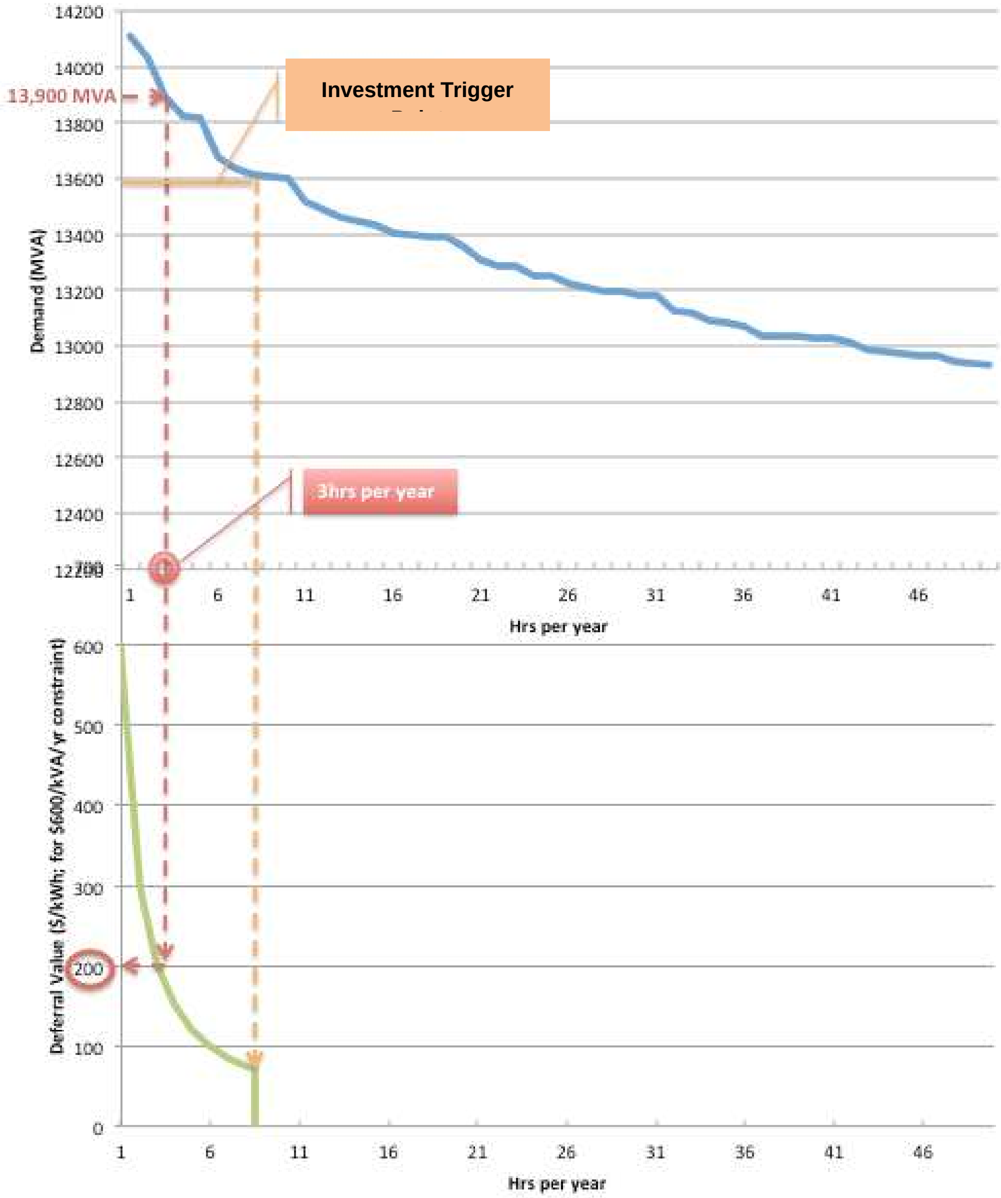
(If we assume that kVA = kW, which is true for a power factor of 1)

Note that the above formula only assigns a cost to the hours of the year **that are above the maximum peak demand in the year prior to the constraint**. This is based on the premise that if network investment is planned for 2014 (for example), then the level of load at risk in 2013 must have been calculated to be an acceptable level of risk to the Distribution Business, otherwise the investment would have been made earlier. Therefore, if DM can return the demand situation to the conditions in the year before it became critical – by offsetting the annual rate of demand growth – then the level of risk must still be within acceptable bounds. Essentially this provides a “cut-off value” (referred to as the “Investment Trigger Point”) for the calculation of hourly costs such that only hours that are considered to have an unacceptable level of risk are assigned a value. This ensures that the total annual deferral value gets distributed according to the critical hours only, and the sum of the hourly deferral values for the year (in $/hr) will never exceed the annual deferral value (in $/yr).

Figure 9 below explains this process graphically. After constructing the (blue) Load Duration Curve (or drawing the load duration curve from user entered 8760 hourly data as was the case for many Victorian substations),[16] the DANCE model reads off the number of hours per year associated with a particular level of demand, and then references this point on a deferral value cost curve (green). The green deferral value cost curve is simply the annual deferral value divided by the number of hours of exceedance. The hypothetical example shown by the red dotted line in Figure 9 is for a particular hour at of the day at which the demand is around 13,900MVA (this example was originally based on the state of NSW). This demand is above the Investment Trigger Point of 13,600 MVA and thus a constraint occurs (in this purely illustrative example the Investment Trigger Point is calculated as the peak value of 14,100MVA minus annual growth of 500MVA, leaving a Investment Trigger Point of 13,600MVA). According to the Load Duration Curve, 13,900MVA is reached for only 3 hours per year, and from the earlier Annual Deferral Value calculation we know that this constraint carries a value of $600/kVA/yr. Reading the corresponding value for 3 hours per year off the $600/kVA/yr cost curve, this translates to $200/kWh deferral value (i.e. as per the above equation: $600/kVA/yr ÷ 3hrs/yr). Note that this is the deferral value for that specific hour only, and the hour before or after will be different, providing the demand is higher or lower. Also note that the deferral value on the cost curve becomes zero at the point at which the Investment Trigger Point is no longer exceeded, as indicated by the orange dotted line in Figure 9.

[16] The authors wish to note their sincere appreciation to the Victorian network business and their staff who provided data and advice, without which this research would not have been possible.

Figure 9: Conceptual diagram of Hourly Deferral Value calculation



This method is applied for the demand at every hour of the year. The “Summer Peak Day Hourly Deferral Value” image (Figure 17) shows the results for this day on the hottest summer day to show the variation across a critical 24-hour period.

4.4.3 Monthly deferral value

By summing the different hourly deferral values ($/kWh) occurring within each month and multiplying by the level of exceedance above the Investment Trigger Point (kVA), this gives us the *total* value of deferral achievable by avoiding network constraints (in $/month). This can then be divided by the maximum exceedance of the Investment Trigger Point during that month to give the monthly deferral value (in $/kVA/month). This is represented by the following equation:

$$Monthly\ Deferral\ Value_y\ [\$/kVA/month] = \frac{\sum_{i=1}^{n}\left(\frac{\$}{kWh_{(i)}} \times kVA_{(i)}\right)}{MAX\left(kVA_y\right) - z}$$

i = the i[th] *hr of the month*
n = the total number of hours in the month
y = month of the year
z = Investment Trigger Point (maximum annual peak load at the substation minus *the annual peak demand growth rate up to the year of planned investment)*
(NB: assumes kVA = kWh, which is true for a power factor of 1)

In the earlier version of the DANCE model used to create the simplified Collingwood Study shown in Figure 18, constraints at the Distribution, Transmission and Sub-transmission levels were assumed to occur at the same time (i.e. coincidence). This means that if the highest demand hour of the year that occurs only once, the maximum hourly value (in $/kWh) will always be the same as the annual deferral value (in $/kVA/yr), according to the above hourly deferral value formula.

However, in practice this is unlikely to be strictly true. Thus the DANCE Model has now been modified to assess the hourly and monthly deferral values at each level (distribution, sub-transmission and transmission) independently, and sums the results. This is more conceptually accurate, as an upstream transmission constraint might peak at 2pm, while the downstream distribution constraint might occur at 6pm, and thus the maximum values are in fact not coincident. Therefore unless the peak hour on the peak day is coincident (according to the load curves entered by the user), the annual maximum hourly value (in $/kWh) will not be the same as the annual deferral value (in $/kVA/yr), unless the annual deferral value stems only from a distribution level constraint.

4.4.4 Monthly peak factors for Victoria

The additional input that is specific to Victoria and differs from the standard DANCE inputs is the “monthly peak factors”. These are used in the process of constructing 8760 hourly data from the basic user inputs, which are used in creating the hourly and monthly deferral value images. These values dictate the spread of maximum and minimum peak demand values in a given month. The monthly peak factors are the peak of the statistically derived average day load curve (the average of the 1am values in a month, 2am values, and so on), divided by the absolute maximum peak demand during that month. A higher value (closer to 100%) represents greater similarity between the average and peak day, and so a smaller spread of demand values. The values for Victoria were derived from three years of hourly NEM data for Victoria. As can be seen in Figure 9, the greatest similarity between average and maximum conditions occurs in winter, while demand in summer is more variable, reflecting strong air conditioning use on relatively infrequent extreme hot days. For a full explanation of the methodology see Langham and Dunstan (2011).

Figure 10: Monthly Peak Factors derived from Victoria-wide NEM Data (average peak day demand as a proportion of maximum peak demand)

4.5 Outputs

There are five primary GIS mapping outputs from DANCE:

1. Available network capacity (MVA)
2. Total network investment (capex – $ millions)
3. Annual marginal deferral value in effective peak season ($/kVA/year)
4. Monthly marginal deferral value across the year ($/kVA/month)
5. Hourly marginal deferral value on key constraint day/s ($/kWh)

The Outputs of the DANCE Model for Greater Melbourne, Geelong, Ballarat and Bendigo are available as separate interactive Google Earth maps accompanying this report.

Each of the above outputs is explained briefly below.

4.5.1 Available capacity in 2015

The map of available capacity is produced for the distribution zones substation level, and is shown in Figure 11 for the Greater Melbourne region in 2015. This is essentially a map of 'firm capacity' according to the relevant reliability criteria (commonly *n-1*),[17] minus the forecast peak demand. The same image is produced for Geelong, Bendigo, Ballarat and Greater Melbourne for each year from 2010 to 2015 so that the user can see the progression of load growth relative to distribution zone substation capacity over time. In

[17] *n-1* refers to reliability criteria whereby supply is still maintained when one transformer or supply line is out of service.

Google Earth the user can use a "Time slider" bar to move between each of the years as desired, or animate the progression of available capacity over time.

The green and yellow colours in Figure 11 indicate distribution zones that have sufficient spare capacity in 2015 (available capacity is above zero), while the pink and red colours (where available capacity is below zero) indicate distribution zones facing growth-related constraints where investment will be needed to ensure reliability is maintained. **Note that** Figure 11 **simply shows available capacity before network or non-network options are taken to alleviate constraints. This is not an image of areas facing risks of power outage.**

The light grey boundaries for each region are the actual zone substation feeder areas as provided by Sustainability Victoria based on 2007 data (with some minor amendments and approximations by ISF for new zones). The blue dots are the approximate locations of the distribution zone substations.[18]

The most striking thing to note from this 2015 image is the number of substations that are above their ***firm*** capacity rating at this time. However, it should be noted that Victoria's network planning methods dictate that available capacity should become negative before investment in network upgrades is made.[19] This is a means of balancing the cost to consumers on one hand, with the risk of power outage on the other. This commonly translates to demand exceeding firm capacity by around 10 MVA (i.e. available capacity reaches -10 MVA) before investment is made, which is why Figure 11 shows so many areas as light pink (-5 to 0 MVA) and medium pink (-15 to -5 MVA).

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[18] Note that some substations have been moved slightly from their actual locations to be physically within the feeder region that they service, which is not always the case.

[19] That is, the calculated value of "Load at Risk" (the value to customers of the amount of energy that would not be supplied if a fault was to occur) should exceed the annual cost of investing in new network infrastructure, before that investment is made.

Figure 11: Available Capacity in Greater Melbourne, 2015 (MVA)

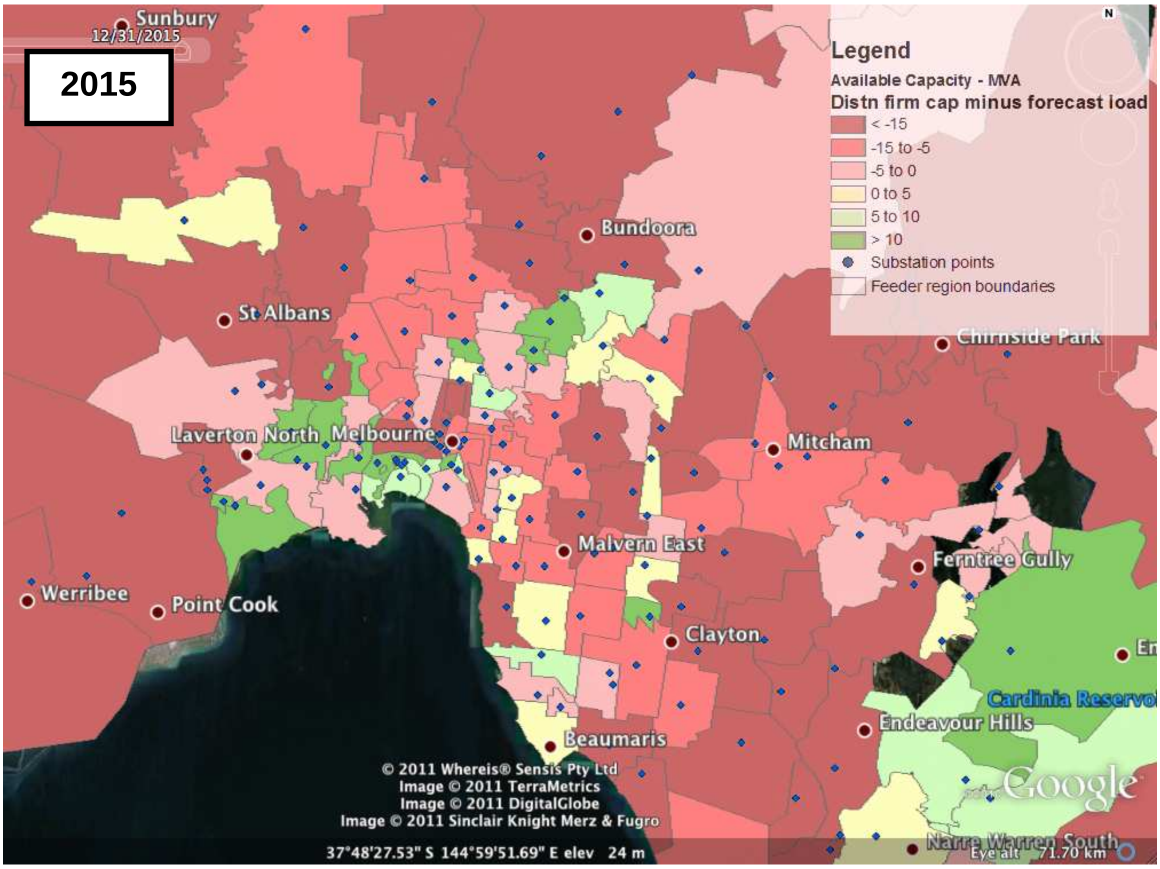
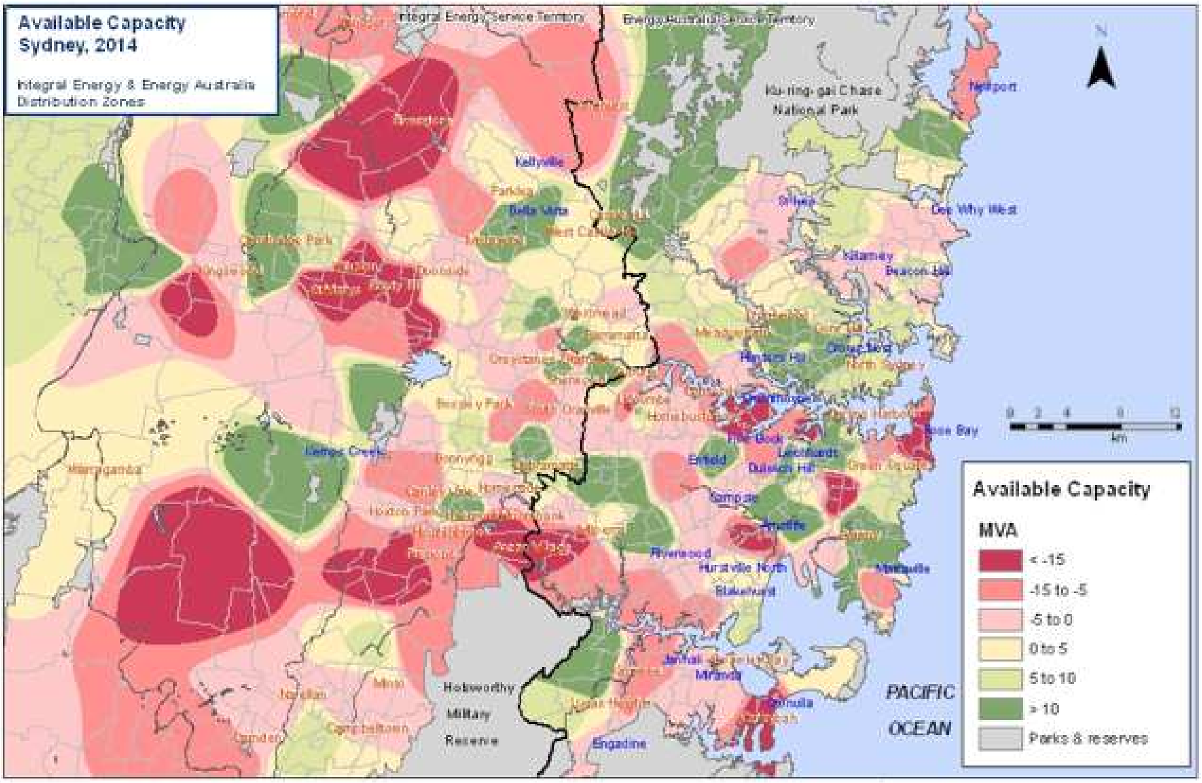


Figure 11 provides an interesting contrast with the image for available capacity for Sydney over the five year planning horizon, which is shown in Figure 12 below. Sydney shows far fewer pink and red zones, as the deterministic planning standards dictate that investment in network upgrades should occur when the firm peak rating is exceeded. This more conservative planning approach carries lower risk of outage and potentially better reliability standards, but also higher associated network augmentation costs.

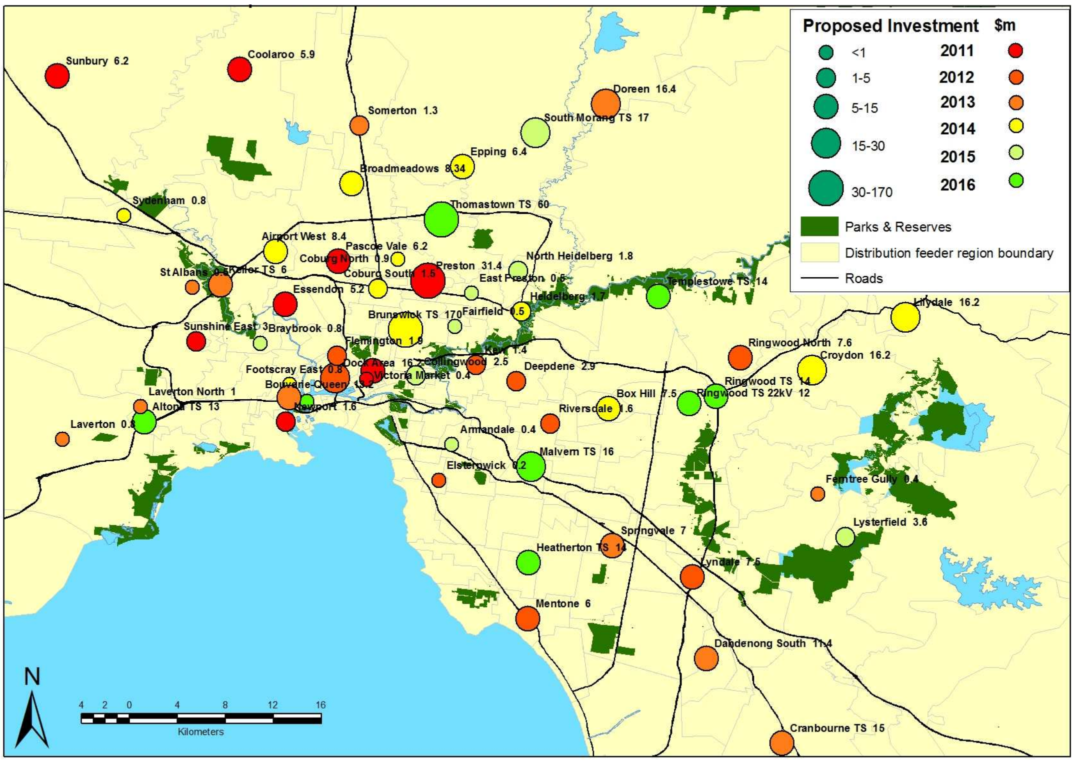
Figure 12: Available Capacity in Greater Sydney, 2014 (MVA)



4.5.2 Planned Network Investment

Figure 13 shows the locations of the planned investment in network augmentations for Greater Melbourne, as reported in the networks' annual Distribution System Planning Reports (DSPRs) and the Transmission Connection Planning Report, published jointly by all networks annually. The size of the dots is proportional to the magnitude of investment, ranging from around $0.5 million up to around $30 million for major new zone substation works, and in the case of a new Brunswick Terminal Station in the north of Melbourne, $170 million. The colour of the dots indicates the year of planned investment, trending red through orange to yellow and then green by 2015 (and post 2015 for some transmission assets where a 10-year planning horizon is used). This colour represents the year in which Demand Management (DM) options would need to be delivering demand reductions sufficient to alleviate the constraint. The number in brackets after the label is the total value in $millions associated with that investment. Equivalent images for Geelong, Bendigo and Ballarat are provided in Appendix A.

Figure 13: Planned Investment in Electricity Network Augmentation
(Greater Melbourne)



4.5.3 Annual Marginal Deferral Value

After taking into account both the planned investment and the rate of growth driving that investment through the Long Run Marginal Cost (LRMC) formula outlined above, we can produce maps showing Annual Marginal Deferral Value, such as those shown in Figure 14. The LRMC is the effective cost of addressing a constraint through the preferred network solution. This annual value (expressed in \$/kVA/year) is essentially an upper bound to the amount that could be spent on non-network options. If less than this amount is spent addressing the constraint using non-network DE options such as distributed generation, peak load management or energy efficiency, then overall the cost to networks and consumers is lower. However, this analysis does not consider any additional network costs, such as those associated with addressing fault level issues in the case of distributed generation. These costs would reduce the value of this type of DM to the network. Further, DM options are generally considered by network businesses to be less reliable than network options, and this may also be reflected in the amount that they are willing to pay DM providers.

For clarity, the LRMC is equivalent to the Annual Marginal Deferral Value. While LRMC is expressed as the marginal cost of network supply, the Annual Marginal Deferral Value is conversely, the potential saving from deferring that investment, which could be used to bolster the business case for Demand Management measures.

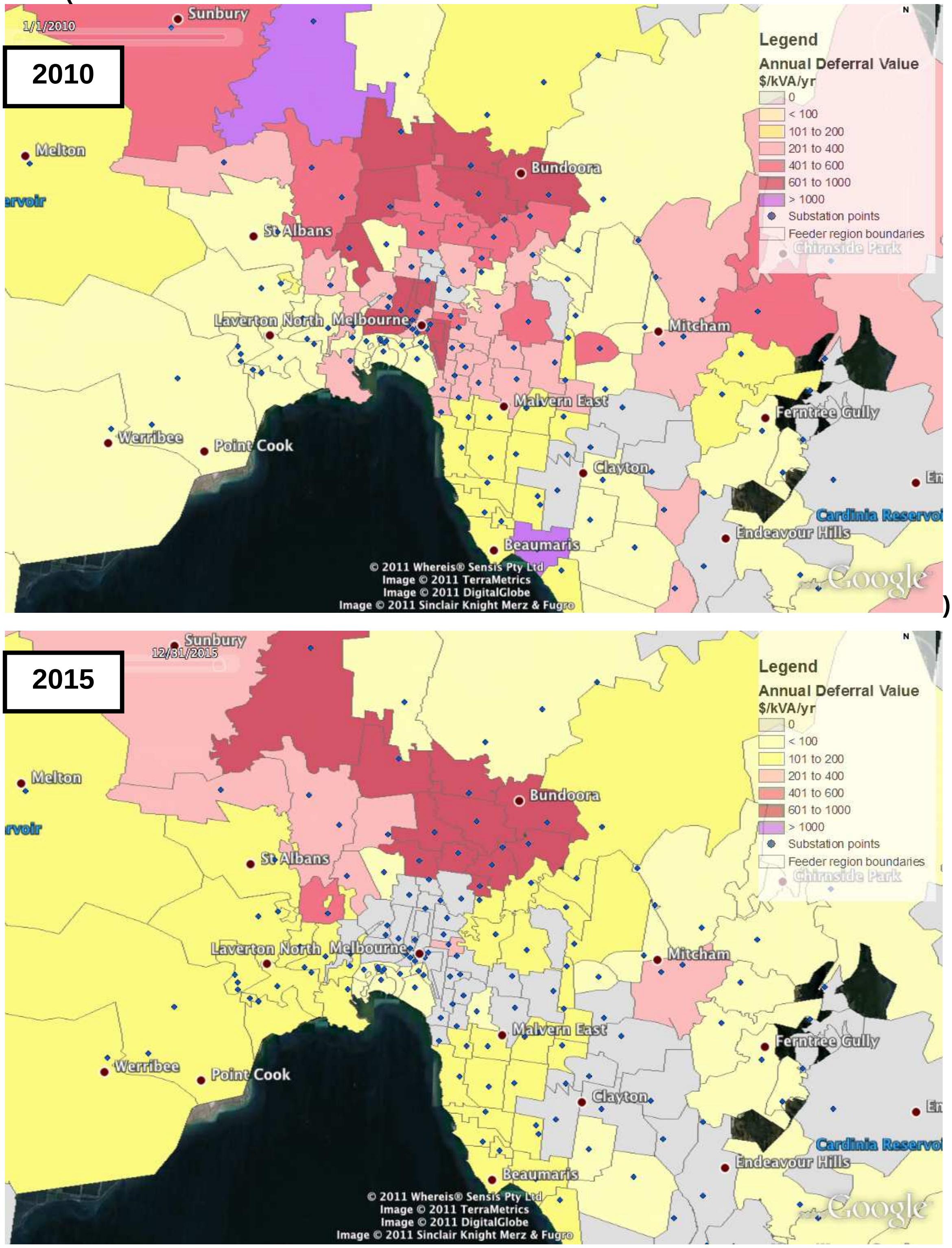
Areas in grey in Figure 14 are those with no deferral value. Areas in yellow are those with limited deferral value that is less than the approximate average cost of network service provision (the average cost of network service provision is generally around \$200/kVA/yr; in

Victoria this figure is approximately $215/kVA/year).[20] Marginal deferral value increases strongly in the areas where the pink colour intensifies ($400-1000/kVA/yr), which are the areas where Demand Management can be highly attractive. The best opportunities for DM are those zones shown in purple, where the values are greater than $1000/kVA/yr.

Note that in the image for 2010 (Figure 14, above), there are many regions where cost-effective DM opportunities are available. By 2015 (Figure 14, below), many of these opportunities are shown to have disappeared. This is because the investment planned for many of those regions has been spent, eliminating the possibility of deferral. What the 2015 image does not show, however, is that there would be new network investments appearing each year with every updated network planning report. Given that we do not yet know where these are going to be, they cannot be mapped and thus the annual marginal deferral value shows far less opportunities in 2015 than in 2010.

[20] Based on combined network revenue of $2.06 billion and system peak demand of 9,323 MVA.

Figure 14: Annual marginal deferral value for Greater Melbourne in 2010 (above) and 2015 (below



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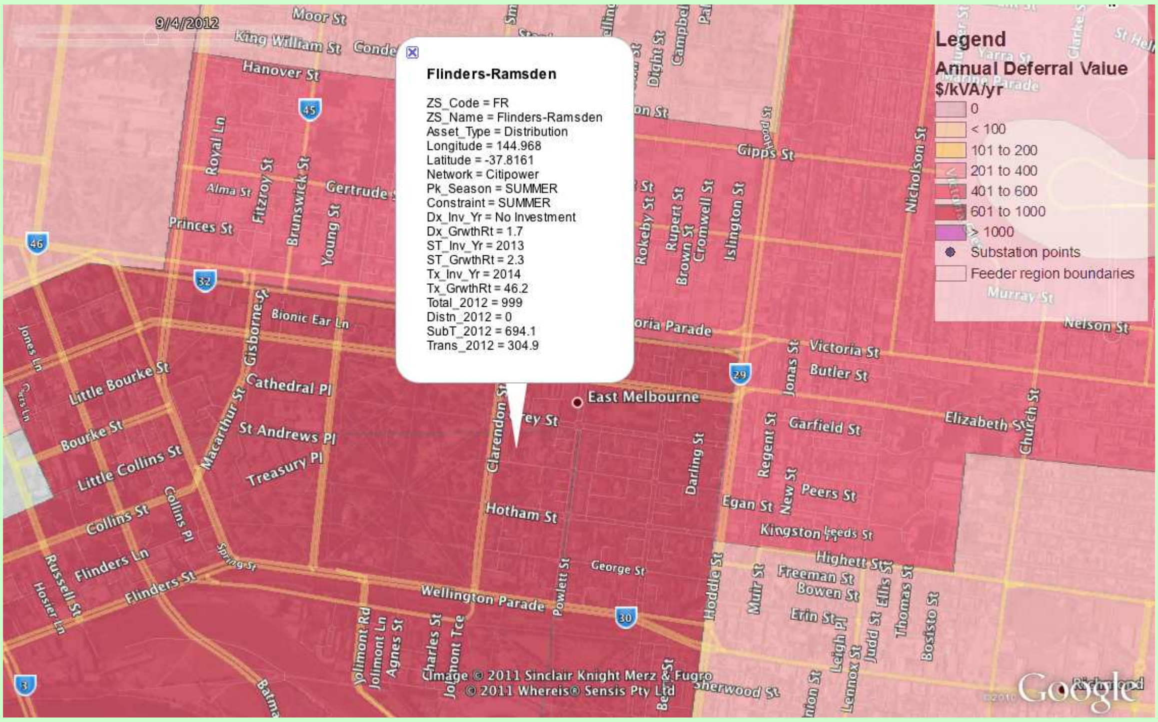
4.5.4 Deferral Value Application Case Study

To illustrate how the annual marginal deferral values are applied, presume that a 2MVA trigeneration operator was to set up in 2012 on Clarendon St, East Melbourne in the deep pink constraint region as shown in Figure 14 (the Flinders-Ramsden Zone which carries an annual deferral value of $999/kVA/yr in 2012).

Figure 15: Example location of embedded generator in Flinders-Ramsden (FR) Zone



If this facility was to contractually provide 2MVA of firm peak power production, and a further 0.5MVA of electrical cooling load offset using the waste heat (which is coincident with the timing of the summer peak), this could assist in deferring the following network infrastructure:

- There is no distribution level investment at this zone before 2015, therefore no value is calculated.
- An $18.1 million sub-transmission investment on the RTS66kV-FR-MP-RTS loop in 2013 valued at $694/kVA/yr, which is driven by a demand growth rate of 2.3MVA/yr. A 2.5MVA firm peak reduction on the network could defer 1.1 years of sub-transmission investment at this growth rate. Therefore the value to the network of that demand reduction is $694/kVA/yr x 2300kVA x 1.1 years = $1.75m.
- A $170 million transmission Terminal Station level investment of $305/kVA/yr, which is driven by a demand growth rate of 46.2 MVA/yr. A 2.5MVA firm peak reduction on the network could only defer such an investment by 0.05 years at this growth rate, and thus to obtain a year's worth of deferral this would need to be part of a broader package of DM measures. Nonetheless, for successful deferral, this would be worth $305/kVA/yr x 46,200kVA x 0.05 years = $0.7m.
- Therefore the total potential value of this embedded generator to the network is $2.45m.

The value for which this DM service is contracted should be *less than* the network option to reduce the cost to the network business, and eventually reduce costs to consumers through lower network charges. Issues around risk of supply malfunction and the alleviation of additional load at risk as may be provided through a network solution also need to be considered by the network in evaluating the value of the DM. Nonetheless, even a fraction of the $2.45m could be important to make the business case for trigeneration stack up. Just one third of the deferral value would amount to around 15% of the capital cost of a 2MVA generator at the standard costs for commercial trigeneration within the D-CODE Model.

Note that when the user clicks on the distribution feeder region as seen in Figure 15, a range of additional information is shown in a white information box. An explanation of the additional pieces of information embedded within each feeder region is given below:

- ZS_Code = The shorthand code used by distribution businesses to refer to this zone substation.
- ZS_Name = The full name of the distribution substation asset servicing this feeder region
- Asset_Type = Whether the network asset is at the Distribution, Sub-Transmission or Transmission level.
- Longitude/Latitude = Geographic coordinates of the zone substation (NB: some have been moved from their precise location for the purposes of this GIS analysis).
- Network = Distribution business operating that zone (NB: some are shared assets and thus areas near service territory boundaries may not be fully reflective of true ownership).
- Pk_Season = the primary season of constraint likely to drive network investment.
- Constraint = the initial season where available capacity becomes negative (usually the same as Pk_Season, but in many cases may be “Both” – this case indicates that there is load at risk in both seasons but that overall the Pk_Season has been classed as the dominant season).
- Dx_Inv_Yr = the year of planned investment at the Distribution zone substation level.
- Dx_GrwthRt = the annual demand growth rate driving any distribution investment (MVA/yr).
- SubT_Inv_Yr = the year of planned investment at the sub-transmission level.
- SubT_GrwthRt = the annual demand growth rate driving any sub-transmission investment (MVA/yr).
- Tx_Inv_Yr = the year of planned investment at the Transmission Terminal Station level.
- Tx_GrwthRt = the annual demand growth rate driving any transmission investment (MVA/yr).
- Total_2011 = TOTAL Annual Marginal Deferral Value in $/kVA/yr (distribution + transmission + sub-transmission)
- Distn_2011 = DISTRIBUTION Annual Marginal Deferral Value ($/kVA/yr)
- SubT_2011 = SUB-TRANSMISSION Annual Marginal Deferral Value ($/kVA/yr)
- Trans_2011 = TRANSMISSION Annual Marginal Deferral Value ($/kVA/yr)

4.5.5 Monthly Marginal Deferral Value

By going further and breaking down the annual deferral value into the months in which those constraints occur, we more clearly articulate the seasonal variation underlying network constraints. It was possible to produce these results with relative accuracy thanks to the specific peak day load curve data provided by network business partners Citipower-Powercor, Jemena, and United Energy Distribution. For SP Ausnet, data was approximated for each distribution substation based on the load curve data at the upstream transmission terminal stations available from AEMO (AEMO Transmission Services, 2010). This Victorian modelling is a substantial advancement on the previous Sydney DANCE case study, which used hypothetical load curve data in the absence of network partners.

Figure 16 shows two examples of the monthly deferral value map, for February and for August, if DM options were implemented in 2011. This takes account of the fact that some substations are not constrained until 2015 or 2020 through a “reverse discounting” approach, whereby if DM is implemented in years before that constraint is imminent, it is worth 7 percent per annum less in each earlier year. The monthly deferral values shown are based on the exceedance of capacity in the first year of constraint, which differs for each substation.[21] This ensures that any network investment that occurs over the time horizon of DANCE is registered in the images. If the specific 2011 situation was shown, substations that are constrained closer to 2015 or 2020 would not appear if they have not have surpassed their firm capacity rating. Conversely, if 2015 was shown, those substations where investment has already been sunk will not appear.

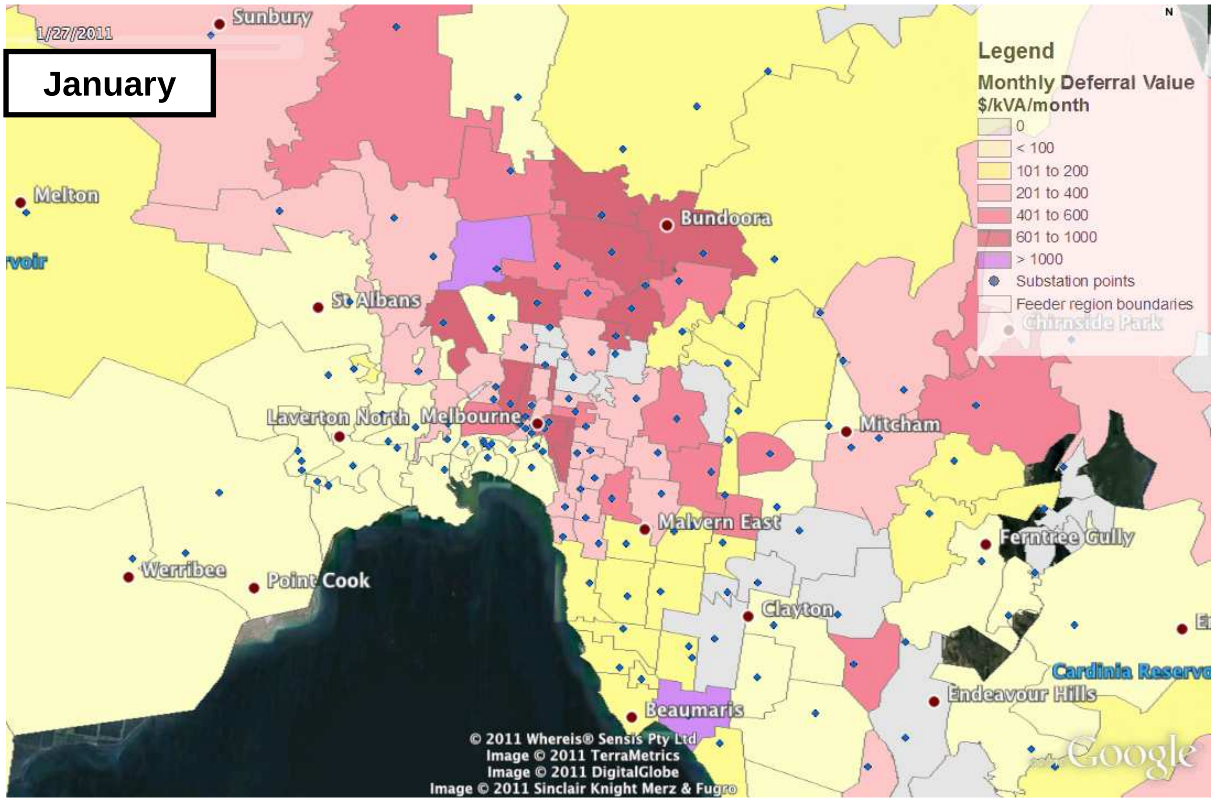
The effective firm capacity is taken as the highest peak demand value in the first year of investment, minus the annual demand growth at the substation. This is consistent with the approach to annual deferral values and is based on the premise that DM will effectively alleviate a constraint if it can keep demand at the level before the growth presented an unacceptable risk to the network.

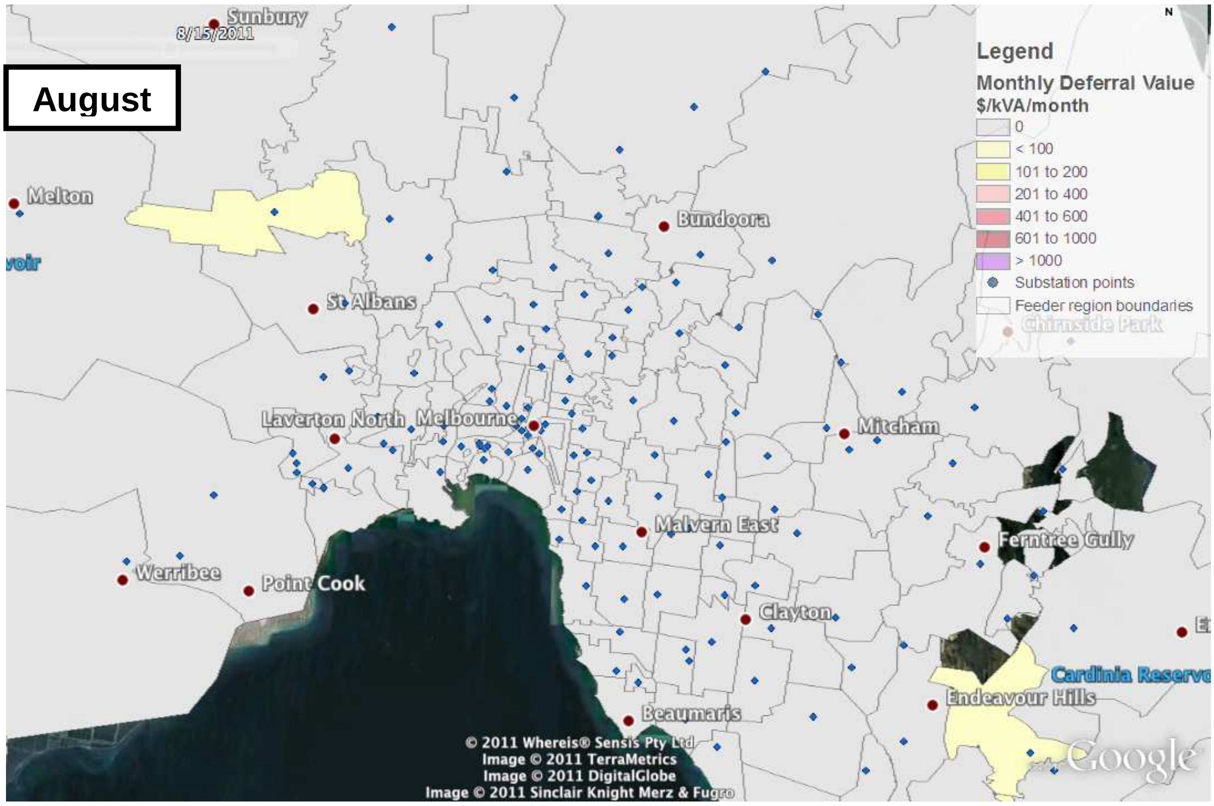
The category classes are the same as for annual deferral value, only the units differ, this time in $/kVA/month instead of per annum. As constraints often only happen in one or two key months per year, the summer or winter monthly $/kVA values are of the same magnitude as the annual $/kVA values, while other months generally show deferral values close to zero.

The outputs shown in Figure 16 demonstrate some interesting differences between February and August deferral values. Note that almost all of the constraints occur in summer, and Victoria has very few solely winter-peaking substations, largely due to increasing penetration of air conditioning and a high penetration of gas for space heating. Those that are winter peaking tend to be in rural areas where those factors driving up summer demand and limiting winter demand are less influential. However, many of the winter peaking values shown for August are in fact not considered by the networks to be winter peaking regions, but stem from the network-provided real demand data being from a year with a mild summer and an unusually cold winter, thus ‘artificially’ shifting the monthly balance towards the winter peak.

[21] This means that for some substations 2010 may be represented, while others may show 2015.

Figure 16: Monthly marginal deferral value for January (above) and August (below)





4.5.6 Hourly Marginal Deferral Value

By showing the deferral value in hourly timeslots on key peak days in which those constraints are occurring, DANCE helps to shed light on the periods during which DM must reduce loads (and inherently the types of electrical loads driving the constraints), and how short the constraint periods actually are driving the billions of dollars of investment outlined in Section 2.2. Figure 17 shows two examples of the hourly deferral value maps, for 1pm and 8pm respectively on the summer peak day (in the year of investment at each relevant substation). The category classes are the same as for the annual and monthly deferral value maps, only the units differ, this time in $/kWh [22] – the most common unit of energy billing. This analysis reveals that even in constrained zones with moderate deferral value of say $400/kWh, this is ***2,000 times*** the ~$0.20/kWh value that a typical residential customer on a flat tariff is actually paying for power at that time. In zones where this tops $1000/kWh this translates to over 5,000 times the flat tariff rate. While these deferral values only apply to those specific limited peak hours throughout the year, it demonstrates the failure of current time of use tariffs (at $0.40/kWh) to pass on accurate cost-reflective pricing signals to consumers to reduce demand.

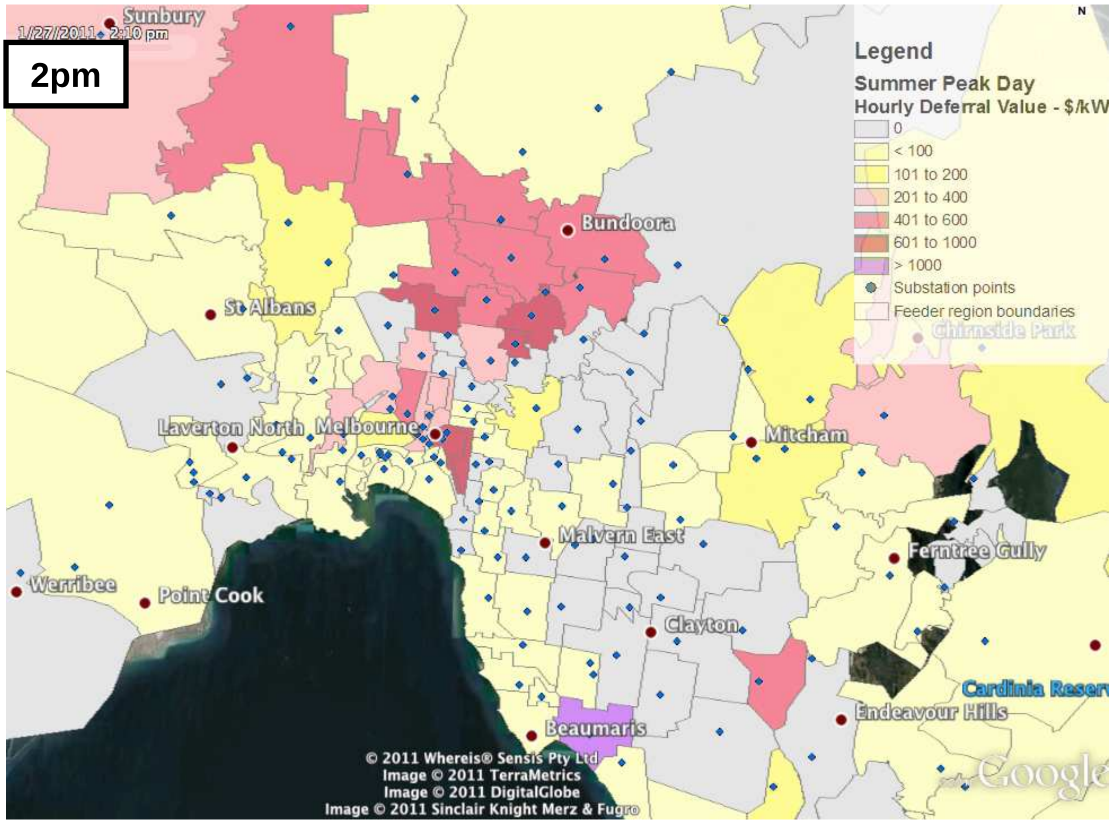
As the values shown in Figure 17 are so high, it would be impossible for truly cost reflective pricing to be implemented at these levels (a customer in a $1000/kWh purple zone using a 1kW air conditioner on the summer peak day would be charged $1000 per hour!). However, while cost-reflective pricing cannot be solely relied upon, there are other options to unlock the potential of efficient DM options. Providers of non-network solutions that alleviate a constraint by reducing peak demand may obtain benefit to some degree if they are offsetting standard tariffs at a particular facility, but as these tariffs are generally far from cost-reflective there remains a large additional margin that could warrant an additional “network support payment”. Effectively striking this balance in crediting network support for efficient non-network options would result in greater uptake of DE, reduced greenhouse gas emissions, and lower expenditure by network businesses on addressing peak demand growth related constraints. This is the key value of the DANCE model to efficient network planning and to the DE industry, by highlighting where and when these opportunities occur.

Note that many of these hourly values are much higher than the Value of Customer Reliability (VCR), which is calculated by Victorian networks to be around $60 per kWh (AEMO 2010b, p.155). This is because the VCR is from a customer’s perspective, and gives the same value of lost load to all load at risk, and the sum of these values must be greater than the annual cost of the network option before the network investment is made. The DANCE hourly values shown above, on the other hand, represent the actual cost of network supply for a given hour, where a higher level of demand costs more to provide than a lower level of demand. This reflects the fact that more severe constraints are more expensive to alleviate, as larger amounts of new capacity need to be built. The DANCE hourly values still

[22] Mathematically $/kVA/hr is the same as $/kVAh, which is roughly equivalent to $/kWh assuming the ‘power factor’ is close to 1.

add up to the annual cost of the network option, but this is spread over a smaller number of hours, as the VCR considers *all* load at risk (i.e. load above the firm capacity), whereas DANCE only considers the load at risk above the previous year's peak demand, after which the load situation became critical (i.e. above the Investment Trigger Point). This reflects the requirement that DM does not have to eliminate all load at risk to be effective, but must contain the value of load at risk within acceptable bounds. Given that the network solution would commonly eliminate all load at risk, DANCE leaves the calculation of these additional benefits of the network solution to the network businesses in determining what they are willing to pay for DM services. Future iterations of DANCE could further engage with the issue of valuing incremental load at risk.

Figure 17: Hourly deferral value for Greater Melbourne on the summer peak day (Top: 2pm, Bottom: 8pm)



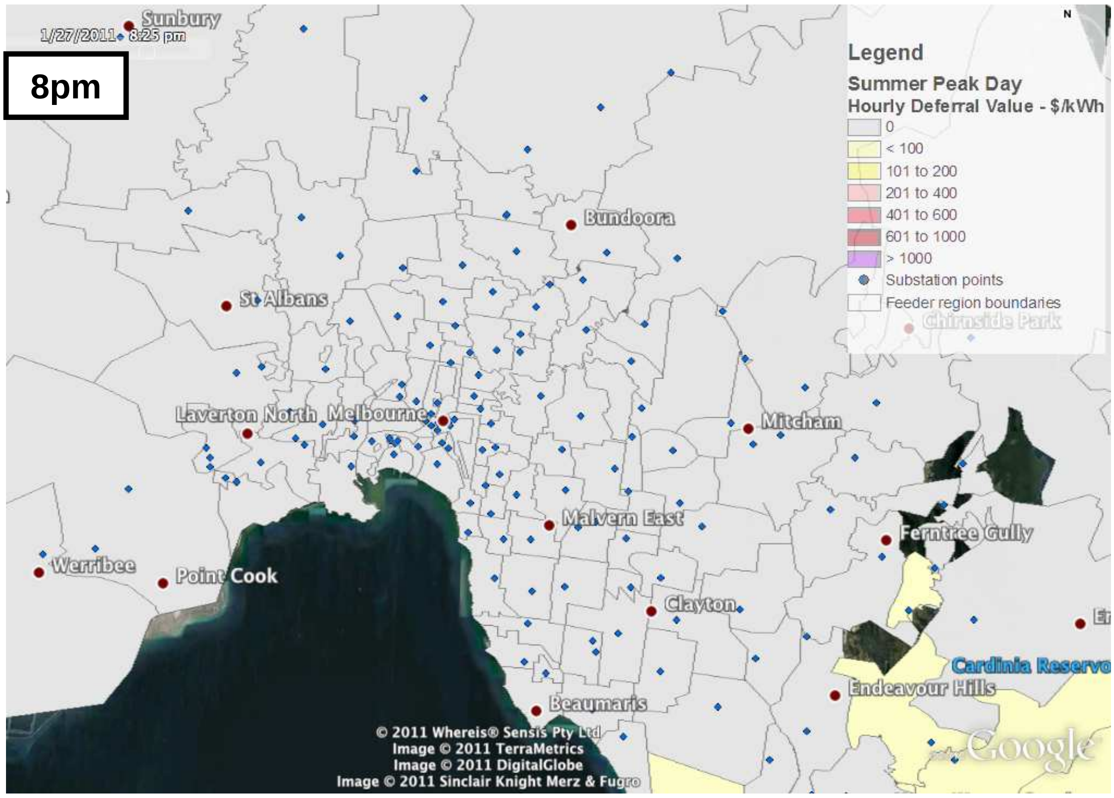
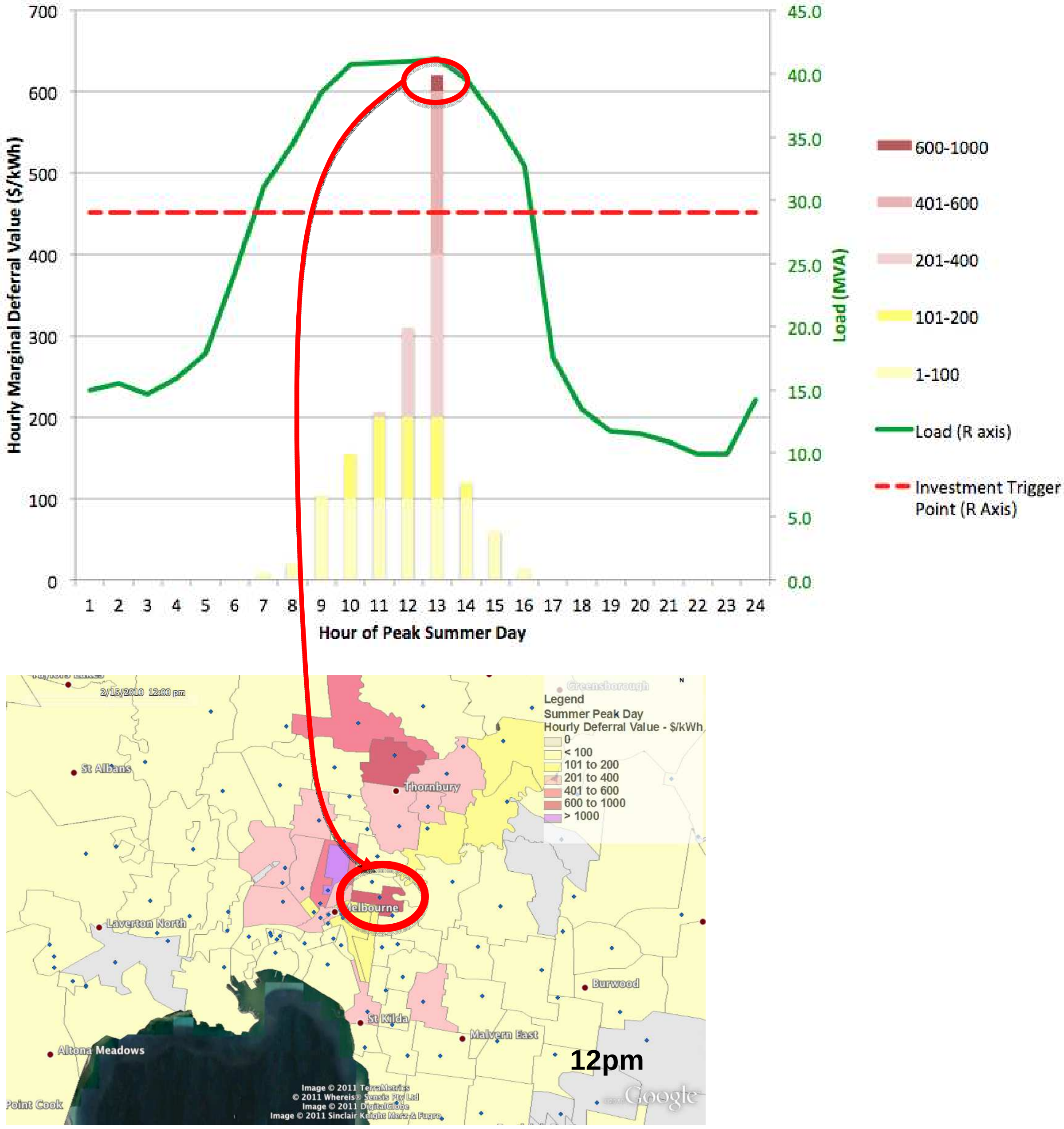


Figure 18 shows a simplified explanatory example of Collingwood Zone Substation how the load on the peak summer day in the first constraint year relates to the firm capacity and annual growth rate of the substation, and the hourly deferral value as it appears in Figure 17. This substation demonstrates a typical summer peak day load curve for a predominantly commercial load area with high air conditioning usage, where demand peaks at around noon (the green line, using the scale on the right hand side). With a firm capacity of around 29 MVA (dotted red line), this level is exceeded for a period of 10 hours, from 6am to 3pm (the unusually early exceedance may relate to the observed peak day being at the end of a heat wave, where temperatures do not fall substantially overnight and buildings remain overheated). Note that as the magnitude of those exceedance increases, so too does the marginal deferral value, as higher demands occur for a shorter period of time. By taking a value of $602/kVA/yr shown in and spreading this across the hours of the year in which firm capacity is exceeded, the peak value reached in the single highest hour is $602/kWh, as shown occurring at 12pm in Figure 18 below. The colours of the top part of the column correspond to the colours attributed to that substation in the hourly charts, as shown in the 4pm image connected by the red arrow.

Figure 18: Simplified example of the relationship between load, investment trigger point, and hourly deferral value (Collingwood Zone Substation)



Note: The above value is simplified for explanatory purposes. Refer to Figure 14 to Figure 17 and the Google Earth map outputs for actual hourly, monthly and annual deferral values at Collingwood and other zones.

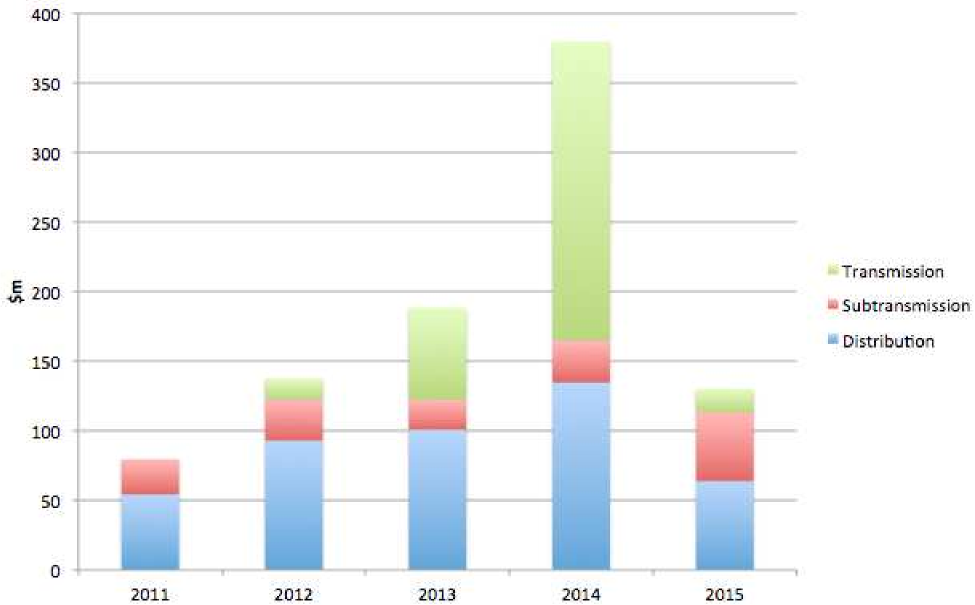
4.6 Analysis

The DANCE Model is largely an exercise in calculating and pinpointing avoidable costs in space and time and thus there are a limited number of broader conclusions that can be made from this information. Nonetheless, there are some general conclusions and points of interest stemming from this research.

4.6.1 Plentiful viable opportunities exist for DM to alleviate network constraints

Despite the lower marginal cost of network augmentation in Victoria relative to other jurisdictions, there are still a large number of value hotspots for DE application to alleviate network constraints. It is recommended that the mapping tools provided through this work form the basis of a demand side engagement strategy for Victorian network businesses, to demonstrate their value in communicating DE opportunities. However, note that numerous opportunities identified address constraints in 2011 and 2012. While some of these may not yet be constructed, they are at least close to or already passed the submission dates for DM service provider proposals to avoid these investments.[23] To fit in with current DM engagement processes of the networks, it is likely to need to look to at least 2013 for feasible opportunities. An analysis of the timing and type of planned network investment reveals that the year for highest proposed investment in network infrastructure is 2014, followed by 2013, then 2012 and 2015. This is illustrated in Figure 19. This is relatively promising in that there are numerous opportunities for the promotion and uptake of DM if it was made a policy priority.

Figure 19: Timing and type of growth-related investment reported in Annual Planning Reports



Data Source: Distribution and Transmission Annual Planning Reports

[23] As part of the Regulatory Investment Test under the National Electricity Rules, prior to large network investments distributors produce a document outlining the different options to address the constraint, and request proposals for DM. Due to the lead time in constructing network options, applications for non-network options generally close well before the construction date.

4.6.2 Differences in approach to DM

There are differences in the approach taken in this research compared to the way that Distribution Businesses generally approach Demand Management. This analysis bases the case for DM on offsetting the annual growth rate at a given substation. This is based on the premise that if network investment is planned for 2014 (for example), then the level of load at risk in 2013 must have been calculated to be an acceptable level of risk to the Distribution Business, otherwise the investment would have been made earlier. Therefore, if DM can return the demand situation to the conditions in the year before they became critical – by offsetting the annual rate of demand growth – then the level of risk must still be within acceptable bounds.

However, the way that Distribution Businesses tender for DM is often not consistent with this approach. This can be illustrated with an example of the proposed $170 million Brunswick Terminal Station (BTS). The annual growth rate leading to the requirement of the construction of BTS is 46.2 MVA/yr. However, the amount of DM called for is 83.7 MVA in 2011, and 189.2 MVA in 2014 (NERA, 2011, Table 4.3). This is because the network solution proposed reduces the load at risk to zero (as it has to be built with excess capacity for future years), and DM is then required to fulfil the same criteria, even though the load at risk in 2013 was considered acceptable (and is still at risk in 2013 even with the network solution). It is, however, possible that planning delays and community concerns in this case forced the delay of the network solution and the acceptance of higher than usual levels of risk. Nonetheless, this general approach appears common to most network businesses in NSW and Victoria.

4.6.3 Importance of transmission level constraint in Melbourne CBD

Much of the avoidable cost in the Melbourne CBD is passed through from the transmission investment occurring at Brunswick Terminal Station (up to $349/kVA/yr in 2014) as this zone is offloading other key Terminal Stations at West Melbourne and Richmond. This new terminal station would become operational in 2014 and would require a substantial lead-time for DM proposals to defer this investment. This project is currently in the planning approval phase and the March 2011 public consultation paper states that DM has not been costed as an alternative to network augmentation due to a lack of DM proposals (NERA, 2011, p.10). This is not unexpected in a fledgling industry where demand management options are rarely adopted when tendered to the market as they are considered to be able to deliver insufficient capacity (as the DM tendering process calls for tens or sometimes hundreds of MW at a time, and an all-or-nothing approach is generally taken).

4.6.4 Network planning standards, reliability and the uncertain future of Victorian network investment

The apparent difference between the network planning processes in NSW and Queensland (which are both seeing record levels of network infrastructure investment) and Victoria is marked. Victoria currently takes a far less conservative approach than these other jurisdictions through its different reliability standards and probabilistic rather than deterministic planning criteria.

While Victoria currently faces one of the lower marginal costs of new network supply in the country, this research raises questions about the future direction of electricity network expenditure in Victoria, given its somewhat anomalous situation of relatively high peak load growth and relatively low network capital expenditure. While Victoria has taken a more proactive approach to smart metering, both Queensland and NSW have significantly tightened their network reliability criteria.

Given than Victoria's peak demand relative to energy growth trend is more severe than other jurisdictions yet network investment is lower, this raises the questions of why other States are currently investing significantly more in network infrastructure or whether Victoria might also face a major increase in network investment in the next (2016-2020) regulatory period.

It is beyond the scope of this report to answer these crucial questions. However, it is pertinent to consider the implications of these questions. If it is the case that Victoria is currently "under-investing" in network infrastructure, then this will eventually be evident through falling network reliability. If this were to occur, it is possible that Victoria could find itself in a situation in the 2016-2020 period of reliability problems, declining load factors, rising network capex, prices and customer bills and rising carbon costs.

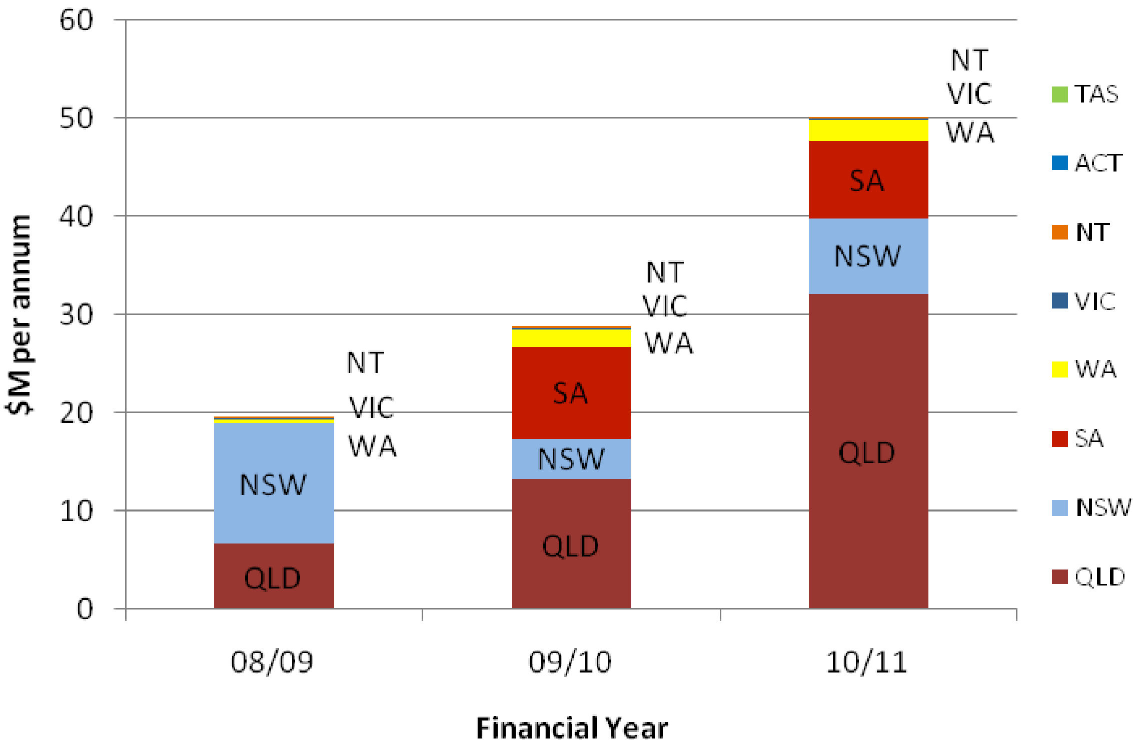
On the other hand, Victoria could take advantage of the current "window of opportunity" to act in advance of other states in promoting DE, before Victoria's strong summer peak demand growth drives more substantial new network expenditure and places additional price pressures on electricity consumers.

Such a strategy could allow Victoria to take a step change towards a more flexible, low-carbon decentralised energy future, while avoiding the severe electricity cost pressures seen in NSW and Queensland.

4.6.5 Current DM regulatory processes are failing

Discussions with network businesses and the review of consultation documents for network augmentation proposals suggests that the current Regulatory Investment Test rarely result in DM being undertaken. This is supported by a recent survey (Dunstan, Ghiotto & Ross, 2011) on the status of DM activities in network businesses around Australia, which – while not a complete dataset – indicates that Victoria is lagging other States in its implementation of DM, as shown in Figure 20. This research suggests that this is not for a lack of DM opportunities, but rather for an inability to tap into those opportunities. Indeed, Section 5.2 of this report estimates 4,270 MW of peak demand reduction opportunities in Victoria, or 39 percent of current peak capacity. Over 1,600MW of peak capacity of energy efficiency and peak load management were deployed in the Optimal Mix modelling case. The inability to tap these opportunities relates to a range of institutional barriers such as a lack of information, a lack of precedents of successful DM in deferring investment, and a host of cultural barriers to changing traditional methods in network planning. For further discussion on barriers to DE & DM see iGrid Working Paper 4.1, available at http://igrid.net.au/node/190. For more discussion on policy tools to overcome these barriers, see Working Paper 4.2 also available on the iGrid website.

Figure 20: Snapshot of Demand Management activity by jurisdiction



4.6.6 Victoria is well placed to lead on incorporating DM network planning

This research indicates that a**n incremental (probabilistic) approach to DM is vital**. Setting artificial hurdles of fixed periods of deferral with large minimum required blocks of DM application effectively sets up DM to fail from the tendering process, and stifles the opportunity to gradually and progressively grow the DM industry. Victoria is well placed to initiate and develop these more flexible processes, as it already operates on a probabilistic network planning model and instituting similar processes for DM application is a small step from current practices relative to other States which are based on deterministic investment triggers. The mapping and analysis tools provided as part of this project provide a foundation for Victorian network businesses to engage DE providers effectively in the network planning process, and for policy makers to communicate to the DE industry the potential value of network support, and the need to better engage with networks on providing reliable demand reduction and tackling issues of contractual risk.

4.6.7 Limitations and areas for further development

There are several limitations of the DANCE Model that may be addressed in future model development:

- There is currently no capacity to deal with multiple network investments in different years. The current approach is to take the first year of investment as the "year of operation" by which DM must be in operation, unless the vast majority of investment occurs in later years, in which case that latter year is used as the trigger year instead. Neither is entirely accurate, but the current approach is as reasonably accurate. There may be potential to improve on this approach in future model iterations.

- All annual deferral values costs are based on the growth rate of the primary peak season. This is almost always summer for Victoria, but where there are multiple constraints (summer and winter) this cannot be reflected in the calculation of monthly and hourly deferral values.
- When using the observed 8760-hour data provided by Network Businesses, the monthly and hourly deferral values reflect the conditions of that particular year, which may have been extreme or mild, and almost certainly does not match the average conditions used for network planning purposes. This creates a small number of situations where a zone is a (narrowly) summer peaking, but in the year of data provided, winter actually saw the highest load conditions. Thus while this does not affect the annual deferral value, the monthly and hourly figures will reflect the observed data, and the highest hourly cost of supply might be shown as winter for a zone that is summer peaking according to the network. While this could causes anomalies, it would only do so in rare circumstances and was thus not considered relevant for this project. This could potentially be addressed in future revisions, of the Model.

5 Costs and Potential of Decentralised Energy in Victoria

5.1 Introduction to the D-CODE Model

Sections 3 and 4 above respectively quantified the potential avoidable network investment, and mapped where within the electricity network those avoidable costs occur. The question that remains, is to what extent a broad portfolio of cost-effective Decentralised Energy options can deliver the network cost savings, while meeting key electricity system energy and capacity requirements. This question is answered through the application of the Description and Costs of Decentralised Energy (D-CODE) Model at the Victorian state level. The D-CODE Model was developed by the Institute for Sustainable Futures under the CSIRO Intelligent Grid (iGrid) Research Program, designed to stimulate discussion on the best way to meet our future electricity needs through the lowest cost, lowest emissions means; and to assist governments, utilities, energy planners and other interested stakeholder groups in making informed decisions about energy supply and usage.

While there are many models that seek to model the costs of different energy supply options,
D-CODE approaches the problem from a different perspective, by:

- including often "hidden" network costs associated with the geographical location of electricity generation relative to electricity consumers; and
- assessing supply-side and demand-side options side-by-side in a single decision support tool.

As DE options, particularly energy efficiency and peak load management, can avoid the need for large network infrastructure costs associated with more centralised supply options, D-CODE reveals the local benefits of DE options over centralised generation expansion. These benefits are often overlooked in a typical levelised cost analysis of generation options. The D-CODE model enables a fairer comparison of 32 technologies and programs to meet Victoria's future electricity needs, ranging from distributed demand side management through to centralised baseload fossil fuel generation. The D-CODE design principles of transparency and simplicity make the model accessible to a wide audience, providing stakeholders with a powerful tool to move towards a lower carbon, lower cost intelligent grid. Detailed information on how the D-CODE Model works can be found in Working Paper 4.3 entitled *Evaluating Costs of Decentralised Energy* (ver. 2) on the iGrid website at: http://igrid.net.au/index.php?q=node/190

For this research, D-CODE has been applied at the Victorian state level using a range of different scenarios to test the business case of DE.

5.2 Potential for DE in Victoria

5.2.1 Installed capacity, energy savings and emissions reduction

Victoria has a significant potential for implementing Decentralised Energy options. Table 5 below outlines the potential distributed supply technologies or demand management options that could be achieved over the 10 years to 2020-21. These figures are based on the economic potential (as opposed to the technical potential) of each technology or program. A full description of each DE technology, including definitions and assumptions used to reach the estimated figures below, is contained in Appendix B.

As can be seen from Table 5, the potential of DE to reduce demand and/or increase supply is relatively large, with potential capacity to meet one third of Victoria's peak demand in 2020, and 31% of projected 2020 energy demand. Full implementation of these DE options would result in greenhouse gas emission of 19 Mt CO_2-e per annum, or 32% of 2010 electricity emissions.

Table 5: Victorian DE potential for peak capacity, annual energy, and emissions reduction

	Firm peak potential, by 2020		Annual Energy generation, by 2020		Emissions	
	Firm peak capacity (MWp)	% of 2020 peak demand[24]	GWh/yr potential by 2020	% of 2020 projected demand[24]	MtCO2e /yr	Reduction potential as % of 2010 electricity emissions
Industrial Energy Efficiency	669	5.08%	3807.9	7.17%	-4.68	-8.09%
Commercial Energy Efficiency	632	4.80%	2601.9	4.90%	-3.20	-5.53%
Residential Energy Efficiency	91	0.69%	192.4	0.36%	-0.24	-0.41%
Residential Hot Water	21	0.16%	918.0	1.73%	-1.08	-1.86%
Commercial & Industrial Demand Management	453	3.44%	14.3	0.03%	-0.02	-0.03%
Residential Demand Management	592	4.50%	163.7	0.31%	-0.20	-0.35%
Commercial & Industrial Standby Generation	211	1.60%	19.4	0.04%	-0.01	-0.02%
Industrial Cogeneration	703	5.34%	4537.7	8.55%	-4.54	-7.84%
Commercial Trigeneration	346	2.63%	1403.0	2.64%	-1.27	-2.19%
Residential Cogeneration	195	1.48%	747.1	1.41%	-0.71	-1.22%
Refuse derived fuel to energy (RDF)	111	0.84%	881.4	1.66%	-1.06	-1.84%
Landfill gas	35.15	0.27%	278.7432	0.52%	-0.33	-0.57%
Sewage gas (Municipal water)	27.55	0.21%	218.4744	0.41%	-0.26	-0.44%
Solar PV (small scale)	184.45	1.40%	623.2302	1.17%	-0.77	-1.32%
TOTAL VIC 2020 DE POTENTIAL	**4270.75**	**32.4%** *(of 13,165MWp)*	**16407.3**	**30.9%** *(of 53101GWh)*	**-19.3**	**-31.71%** *(compared to 57.9 $MtCO_2$)*

[24] Based on 2.2% and 0.93% annual average growth of peak and energy demand respectively, medium growth scenarios (AEMO 2010a).

5.3 Supply-demand balance in Victoria to 2020

Victoria's existing peak supply capacity is 10,921 MW, while AEMO demand projections for 2020 suggest peak demand of 13,165 MW. This leaves a capacity shortfall of 2,244 MW.

Victoria's existing energy generation capacity is 57,880 GWh/a, while AEMO energy projections for 2020 suggest required energy generation of 53,101 GWh/a (AEMO 2010a). This means that Victoria's existing supply base is sufficient to meet energy demand in 2020 (with a surplus of 4,779 GWh/a) assuming that no current generation assets are retired. There are, however, several coal-fired generation assets that have already passed or will soon pass their planned economic working lifespan of approximately 40 years, including (by 2010-11) Hazelwood, Yallourn W, Anglesea and Morwell; and (by 2014-15) Loy Yang A. It is for this reason that although there is no energy shortfall if these power stations continue to operate beyond their projected lifespan, a scenario is run to explore the role that DE could play if one major 1600MW brown coal power station was retired.

The above AEMO demand projections are based on the medium demand growth scenario outline in the AEMO Statement of Opportunities, where peak and energy demand increase peak by an average of 2.2% and 0.9% per year respectively (AEMO 2010a).

5.4 DE and centralised generation cost comparisons

The primary D-CODE outputs are cost curves that compare the cost and potential magnitude of opportunity for supply-side and demand-side options to meet our future energy system needs. D-CODE integrates both demand and supply-side options on the same curve, allowing straightforward comparison for least cost electricity service delivery.[25]

The data is normalised by annualising capital costs to allow cost comparison of technologies with different project life spans. As some technologies are used primarily for energy generation and others more for peak generation (or peak demand reduction), the data has been normalised to two sets of units and presented on two types of cost curves:

1. Annual energy generation (in $/MWh, see Figure 21 below); and
2. Peak power generation (in $m/MWp, see Figure 22 below).

In both Figure 21 and Figure 22 below, the vertical axis represents the costs, which are broken down into components (represented by different colours) to provide detailed insight into the cost composition of each technology. The horizontal axis represents the quantity of that technology that could potentially be developed in Victoria. Importantly, these graphs include network cost estimates associated with each technology, and therefore highlight the benefits of DE options (through avoiding the need for network infrastructure), which are typically not captured by standard levelised cost comparisons. Note that standardised grid

[25] Throughout this document, we often refer to both the supply side (generation technologies) and demand side (demand management programs or technologies) simply as 'technologies'.

connection costs for generators are included in the D-CODE estimates for the *capital cost* of each technology (blue component), while deep connection costs such as those associated with the fault level augmentation issues are covered by the network cost factor (red component). Although note that D-CODE is limited to a single cost for a particular technology, and thus cannot reflect differences in economics of different projects associated with siting and resource characteristics that improve or detract from the business case.

Figure 21: Cost and potential of energy generation in Victoria ($/MWh)

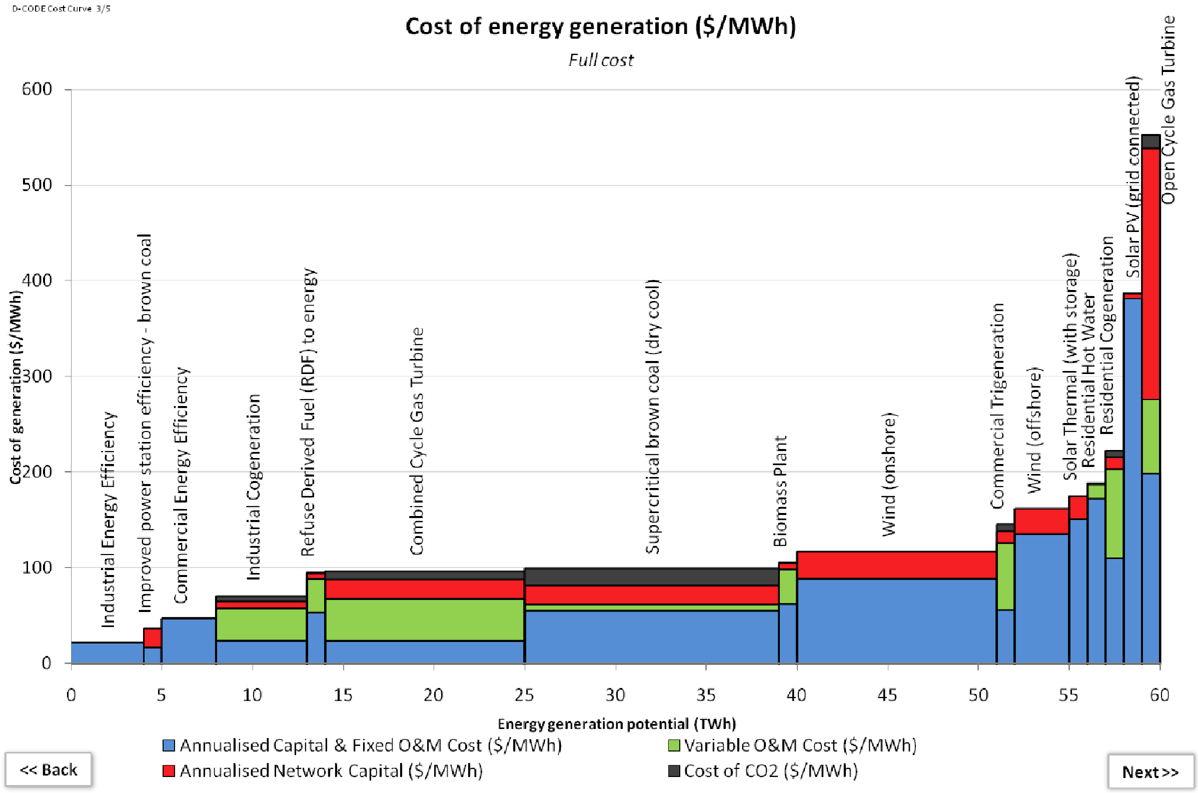
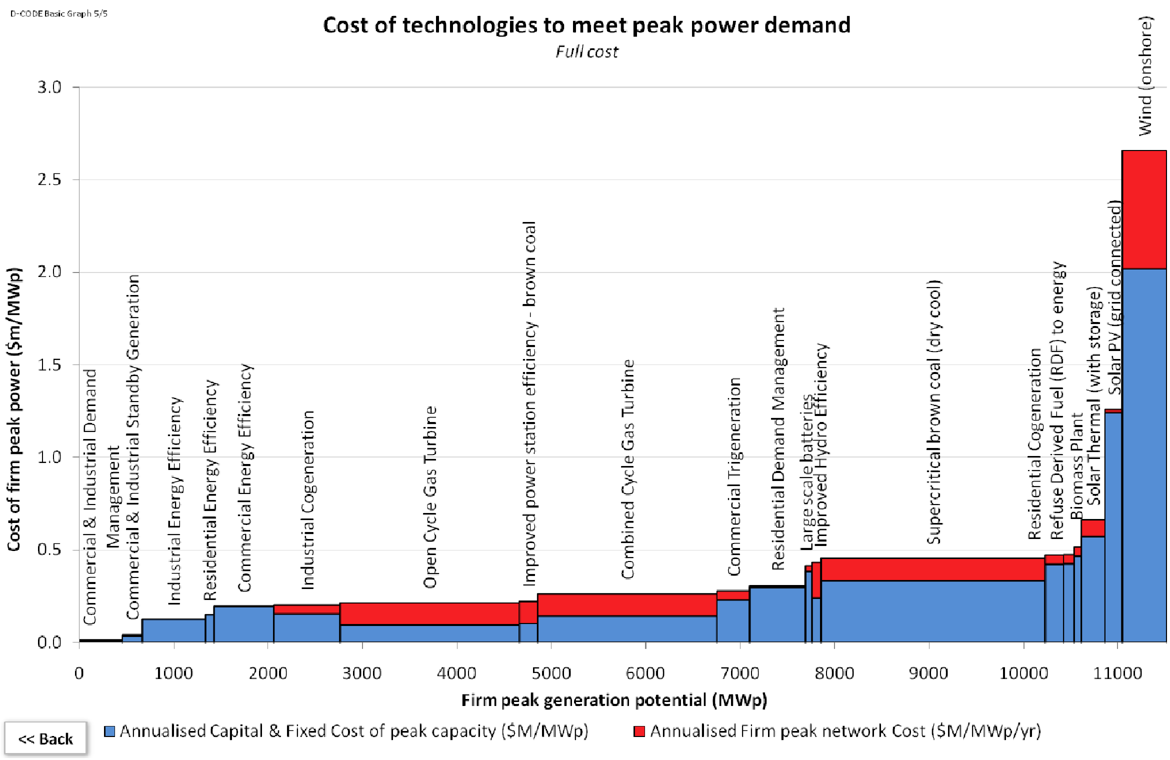


Figure 22: Cost and potential of supplying peak power ($m/MWp)



Each of the cost curves has a separate purpose. If the electricity system in question is approaching a *peak capacity* constraint such as in Victoria, the peak power generation curve (Figure 22) provides an indication of the cost and quantity of installing additional capacity over the planning timeframe. If the electricity system requires additional *energy* supply, the energy cost curve (Figure 21) will provide an indication of the cost and quantity of meeting additional energy demands over the planning timeframe. Often an electricity system may require both additional annual energy generation and peak power generation. D-CODE's Optimum Mix Analysis (OMA) is designed to select the lowest cost mix of technologies to satisfy complex concurrent shortfalls in annual energy generation and peak power capacity. This is the tool used for the D-CODE scenarios, discussed in more detail later in this section.

In terms of energy supply, Figure 21 demonstrates that energy efficiency options in particular offer large potential to reduce costs to customers, in part because there are no network augmentation costs associated with alleviating energy constraints through *demand reduction*. These options are towards the centre-left of the graph. Some Distributed Generation options such as Industrial Cogeneration also look attractive from a cost perspective in this Victorian analysis. Other Distributed Generation options such as Commercial Trigeneration look somewhat less attractive, however it is worth noting that there are a range of costs associated with each technology, depending on the site of application, and the figures in D-CODE merely represent a mid-range scenario. Centralised renewable energy options such as large scale wind and solar thermal look less competitive in this analysis as they involve relatively high equipment capital costs (in blue), as well as relatively large transmission and distribution capacities (in red) to deliver electricity to large consumer bases in more urbanised centres. Fossil fuel generators have larger variable operating costs (in green), as there are fuel costs associated with energy production – unlike renewable energy or demand-side options. Note also that technologies that are specifically peak-power demand supply options are expensive, such as Open Cycle Gas Turbines, which are at the far right of the cost curve for energy generation.

In terms of peak capacity, Figure 22 demonstrates that peak load management options as well as some energy efficiency options offer large potential to reduce costs to customers, again in part because there are comparatively low network augmentation costs in Victoria associated with meeting energy constraints through peak load reduction. These options are clustered towards the left of the graph. Distributed Generation options such as cogeneration look relatively cost effective compared with centralised options. Centralised renewable energy options such as large scale wind and solar thermal look less competitive in this analysis as they involve relatively high equipment capital costs (in blue), as well as relatively large transmission and distribution capacities (in red) to deliver electricity to large consumer bases in more urbanised centres. Fossil fuel generators have larger variable operating costs (in green), as there are fuel costs associated with energy production – unlike renewable energy or demand-side options. Note also that technologies that are specifically baseload power suppliers such as coal-fired generation are expensive to supply peak power but peaking fossil fuel plants such as Open Cycle Gas Turbines (the current 'default' supply-side option for meeting peak constraints) are fairly cheap.

D-CODE's Optimum Mix Analysis used for the scenarios below deploys the lowest cost options in the 'left to right' order shown in the Figure 21 and Figure 22 above to the deployment potential specified in the model. For the DE options this is shown in Table 5 earlier in the report.

5.5 D-CODE Scenarios

D-CODE's Optimum Mix Analysis (OMA) was then used to model the lowest cost deployment of technologies and programs to meet the future energy needs of electricity system. The model user can create scenarios that are run through a linear-programming model to determine the optimum mix of technologies and programs that satisfy both future peak demand and annual energy demand, at lowest cost. The costs and emissions of the optimum mix scenario were then compared to a business-as-usual (BAU) scenario via graphical and numerical outputs. Further detail on the OMA computations and how the user sets-up, runs and interprets the OMA is outlined in the Working Paper 4.3 on the iGrid website.

To explore the opportunities for DE in Victoria, three scenarios were run:

1. Business as usual ('BAU': includes 20% Renewable Energy Target and excludes consideration of network costs).
2. Decentralised Energy deployment ('DE': includes 20% Renewable Energy Target; based on lowest cost deployment of *all* technologies but with consideration of network costs).
3. As per Scenario 2 with retirement of 1600 MW of coal fired power generating capacity.

All scenarios assume a $23/t$CO_2$-e carbon price for consistency as the focus of this research is not on testing the effectiveness of a carbon price.

Note that the technologies deployed and associated costs and emissions shown in the Scenarios below are only those required to fill the capacity and/or energy shortfalls faced over the time horizon of the analysis (to 2020 in this case). This deployment is additional to existing capacity (the only exception to this statement is in the case where cheaper energy efficiency deployed to meet a peak capacity constraint also displaces existing fossil fuel generation – in this case, both variable operating costs and emissions of the electricity system are reduced).

5.5.1 Scenario 1: Business as Usual (BAU)

In this scenario, network costs are ignored and only renewable and bioenergy and centralised fossil fuel generation are deployed, which approximates the status quo in terms of institutional barriers to distributed energy options in the current regulatory and market environment. The outputs of this scenario are shown below in Figure 23 and Figure 24. Figure 23 shows each technology deployed to meet the specified shortfalls in the scenario, which in this case is purely a peak demand shortfall (as outlined in section 5.3). Remember that this is not the entire energy supply mix, but rather the supply mix to meet the shortfall only. Figure 24 shows that technologies employed to meet peak capacity are a mixture of centralised fossil fuel (73%; primarily Open Cycle Gas Turbine peaking plants) and renewable energy (27%, including 12% bioenergy) generators.

While there are no energy generation constraints as such (only a peak capacity shortfall exists by 2020 – refer to Section 5.3), the forced deployment of new renewables under the RET as well as some new technologies to supply peak capacity results in new energy supply of 9,662 GWh/a, which displaces existing energy generation. The major contributors to energy supply are renewables with half of additional energy supply/demand reduction, a quarter of bioenergy, and around 20% from centralised fossil fuels. All of the renewables are forced into the supply mix due to the existence of the Federal Renewable Energy Target of 20% renewable energy by 2020. While this does not necessarily mean Victoria will be home to 20 percent renewable energy supply, most analyses suggest that this is level of deployment what is likely to occur (MMA 2010; Carbon Market Economics 2009). Therefore 20% renewables is ‘forced’ into the mix in least cost order, which is why wind power dominates as the lowest cost option when network costs are not included in the cost equation.

Figure 23: Deployed capacity of each technology to meet peak constraint under BAU Scenario (MWp)

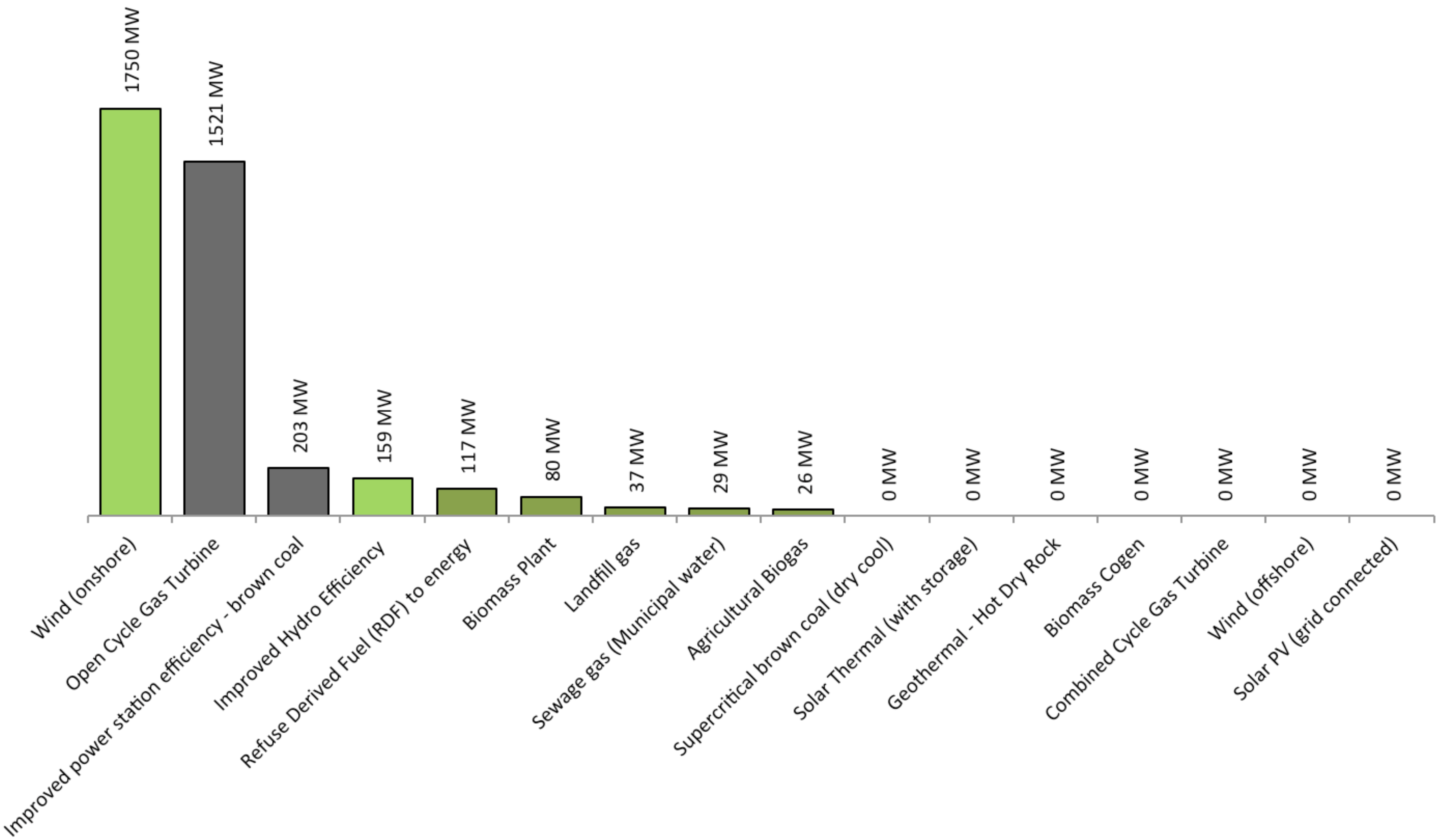
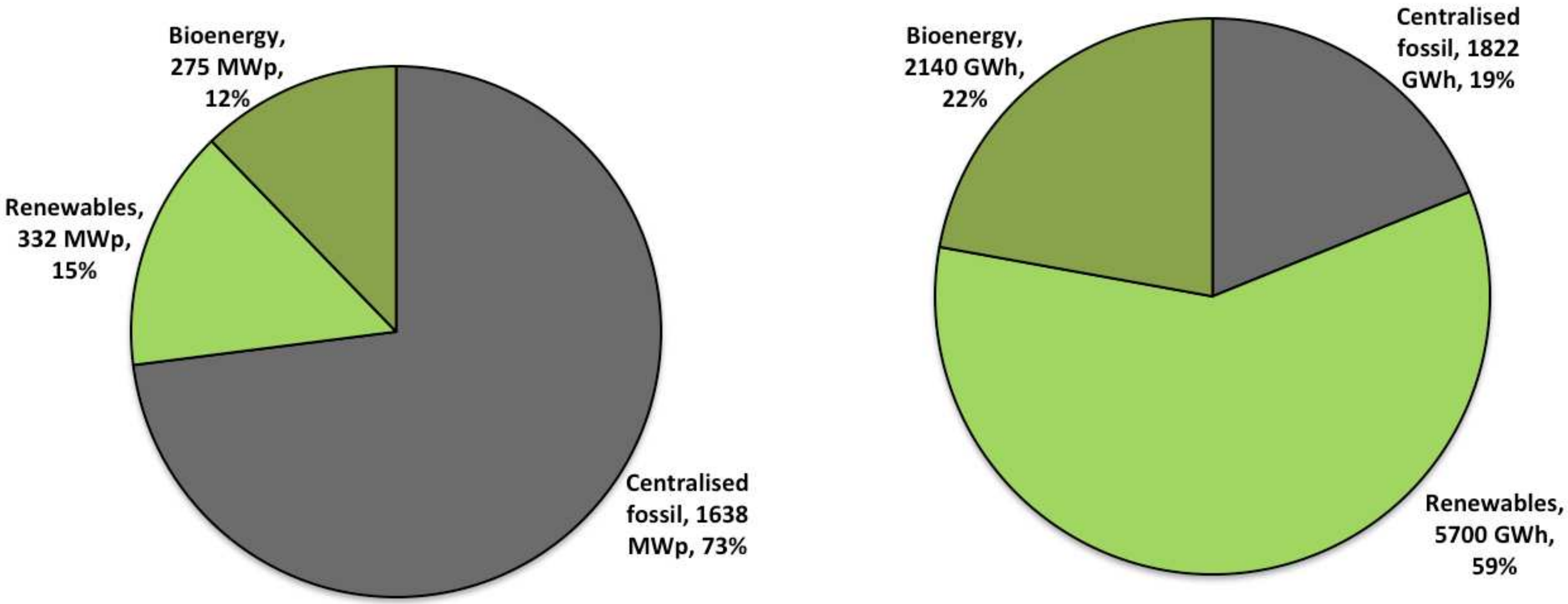


Figure 24: Technology types meeting peak capacity (left) and energy (right) shortfall in BAU scenario



5.5.2 Scenario 2: Least Cost Technologies (Decentralised Energy)

In this scenario, network costs are included and all technologies – including all DE options – are then deployed in least cost order. This scenario is designed to approximate the current environment with the institutional barriers to DE removed, such as regulatory obstructions, lack of information and inefficient and poorly cost reflective pricing structures. The outputs of this scenario are shown below in Figure 25 and Figure 26. Figure 25 shows each technology deployed to meet the specified peak demand shortfall (see section 5.3). Figure 26 shows that technologies employed to meet peak capacity are a mixture of industrial and commercial energy efficiency (43%), which has reasonable impact on reducing summer peak demand, and peak demand management (30%) primarily in commercial and industrial sectors. Renewables and bioenergy still contribute 27%, as these are forced by the RET. No new fossil fuel generation is deployed.

The major contributors to energy supply are energy efficiency with 42%, and renewables and bioenergy with 58%. Interestingly, the level of "additional energy supply" is greater than in the BAU case, as lower marginal supply cost options such as wind power and particularly energy efficiency *displace* existing fossil fuel generators, by around 2,200 GWh per annum.

Note that no distributed generation options such as commercial trigeneration were deployed in this scenario, as the specific cost and energy and peak load characteristics of these technologies did not fit the needs specified in the scenario. Adjusting other variables would alter these results including the level of *energy* shortfall (as is explored in Scenario 3), technology cost (for sites where better than average cost effectiveness applies or costs come down), gas price, carbon price, or the marginal cost of network augmentation.

Figure 25: Deployed capacity of each technology to meet peak constraint under DE Scenario (MWp)

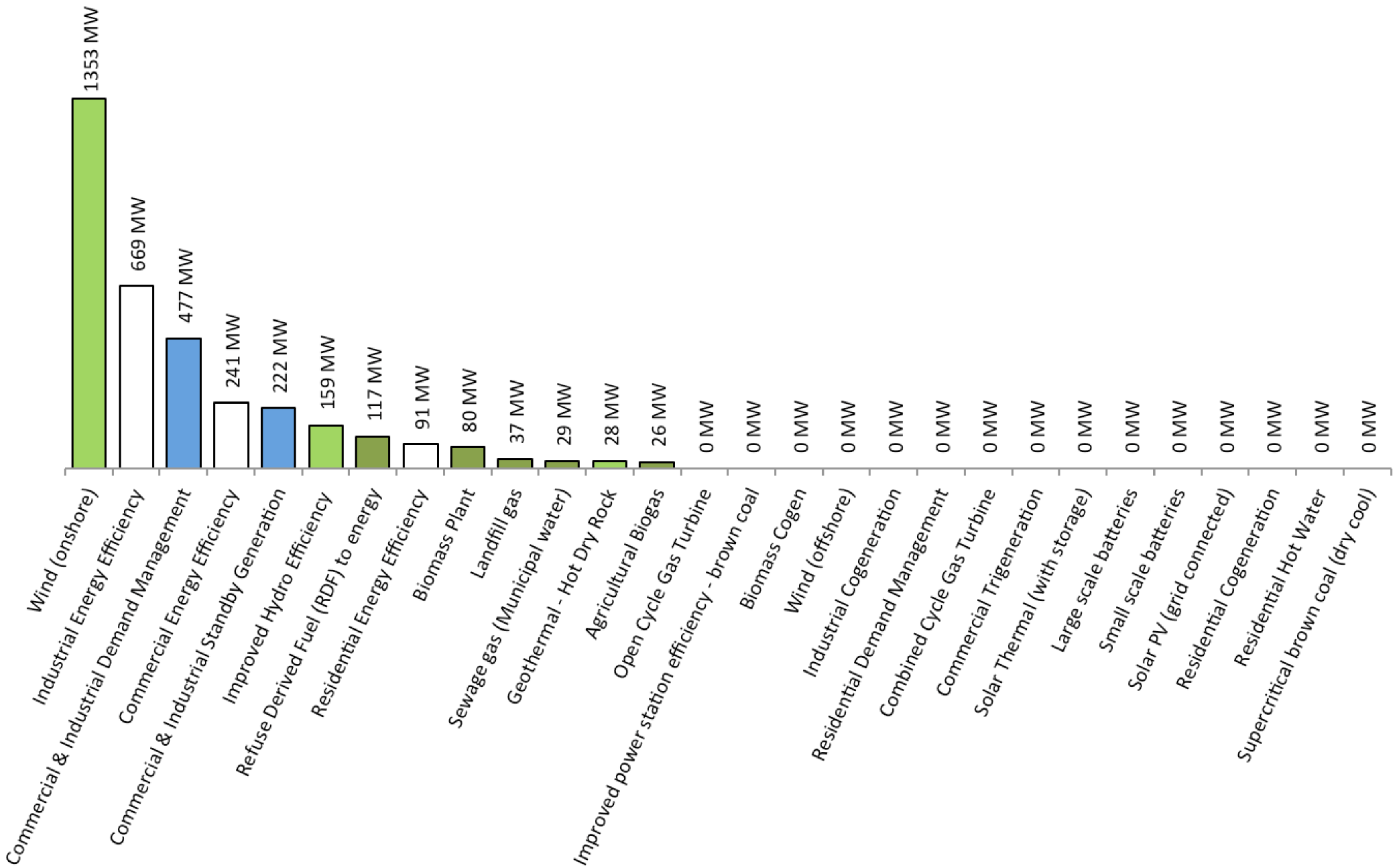
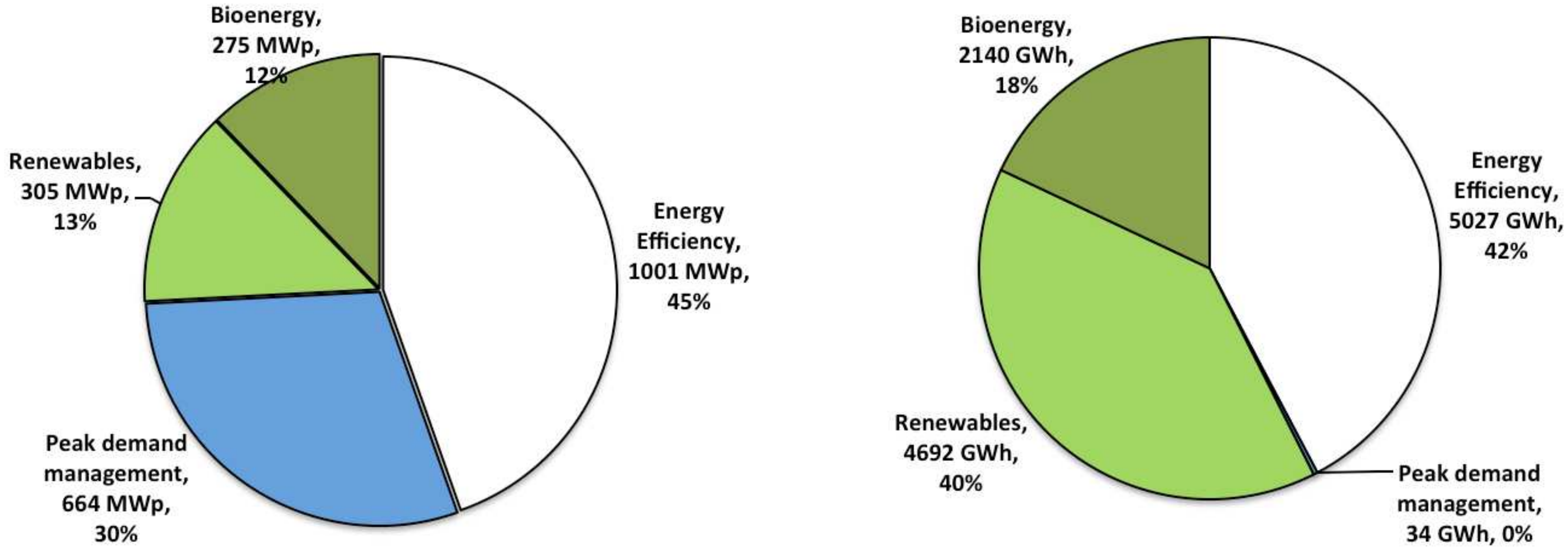


Figure 26: Technology types meeting peak capacity (left) and energy (right) mix in DE scenario



5.5.3 Scenario 3: Coal retirement (1600 MW) using least cost technologies

This scenario has been included to investigate what would happen if Victoria actually had concurrent peak capacity *and* energy generation shortfalls by 2020. The scenario carries planning relevance given that some coal fired power stations have passed their regular lifespans and have a limited number of operating years remaining. Additionally, the federal government is currently tendering to retire 2,000 MW of coal-fired generation as part of its Clean Energy Future emission reduction strategy, which may result in closure of a Victorian coal generating capacity. This creates a situation of a peak shortfall of 3,973 MW and an energy shortfall of 4,385 GWh per annum. As per Scenario 2, all technologies are deployed according to least cost order after including network costs. Also as per Scenario 2, Scenario 3 represents an environment with the institutional barriers to decentralised energy removed. The outputs of this scenario are shown below in Figure 27 and Figure 28. Figure 27 shows each technology deployed to meet the specified peak demand shortfall, which is by far the most diverse technology mix of the three scenarios to meet the more complex conditions associated with a concurrent energy and peak shortfall. Not only are combinations of a wide range of DE options deployed, but also centralised gas peaking plants, improved efficiency of existing centralised supply options, and biomass cogeneration come into the mix. Figure 28 shows that technologies employed to meet peak capacity are a mixture of a third energy efficiency, a third centralised fossil fuels and the remainder made up by peak demand management as well as some renewables and biofuels.

Interestingly, in regard to energy supply, the shortfall from retiring 1600 MW of brown coal generation is met 90% by energy efficiency, renewables and bioenergy, with only 10% met by more efficient forms of fossil fuel supply. As will be shown in the next section, emissions from this scenario drop dramatically, to less than 6% above 1990 levels, as compared to 21% above 1990 levels in the BAU case.

Figure 27: Deployed capacity of each technology to meet peak constraint under 1600 MW Coal Retirement Scenario (MWp)

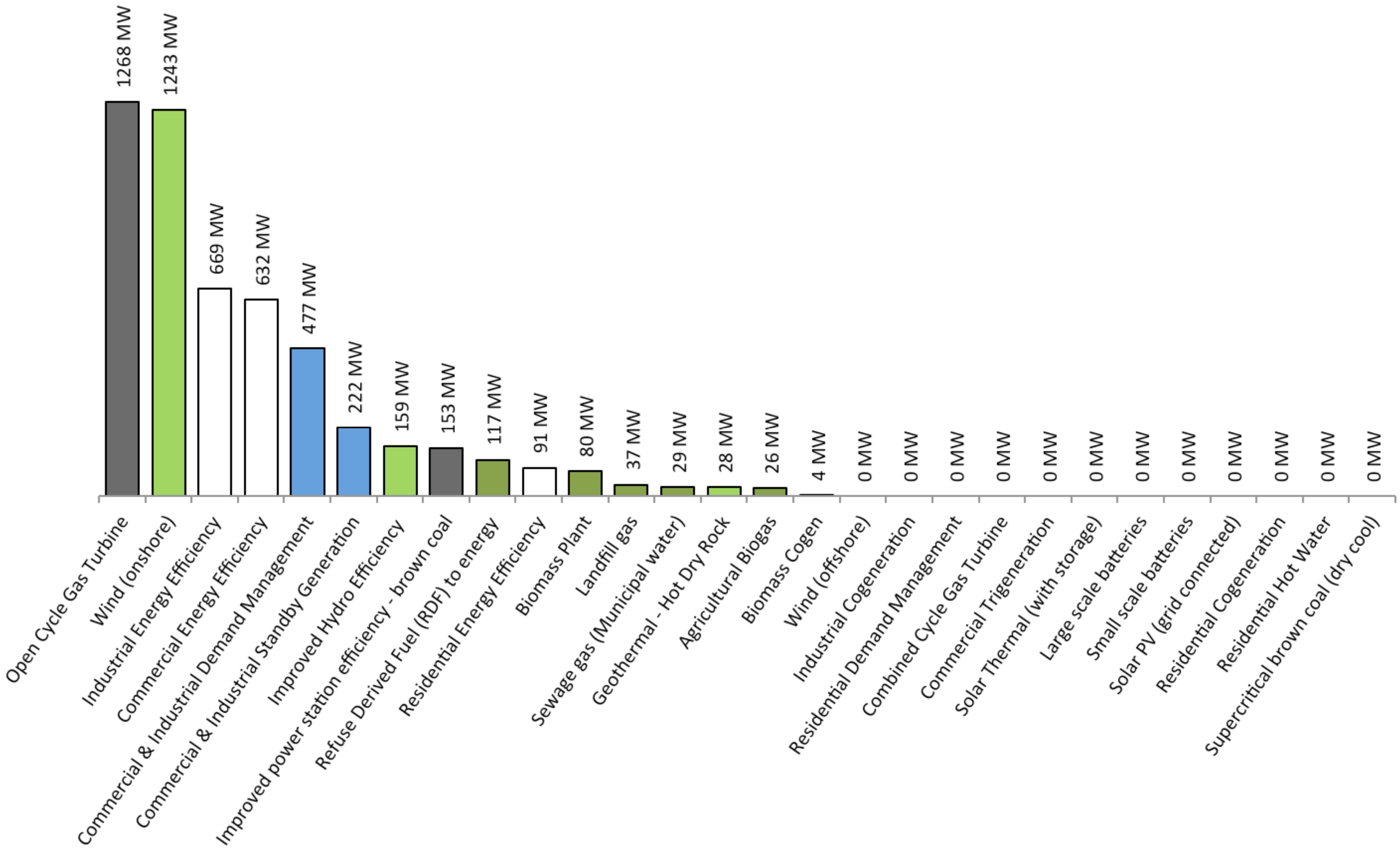
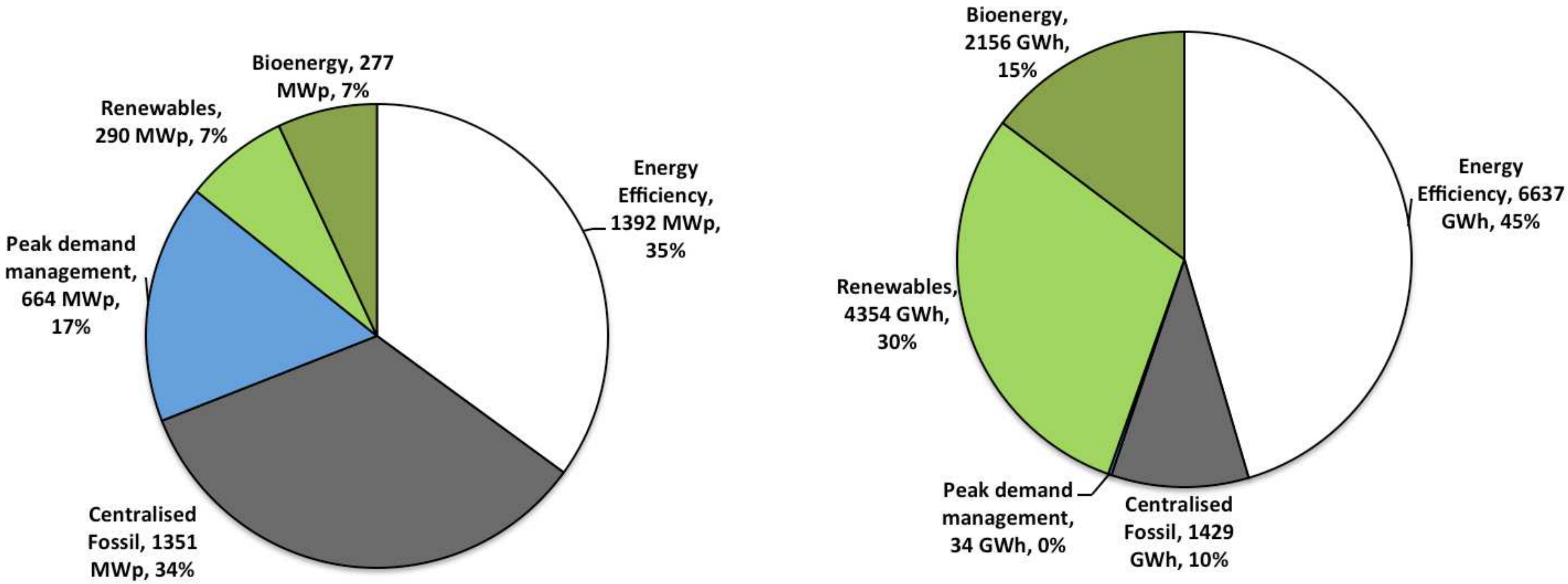


Figure 28: Coal Retirement scenario – Meeting peak capacity (left) and energy (right) mix requirements



5.5.4 Scenario costs and emissions compared

We have seen that the inclusion of network costs into the equation can have a dramatic impact on the energy supply options that are considered cost effective from a societal perspective, even in Victoria which has one of the lowest marginal costs of new network supply in the country. Now the total costs of each scenario will be compared side by side, along with emissions reductions.

As shown in Figure 29, the total costs of the primarily DE scenario (Scenario 2) are $437 million per annum lower than BAU. This is made up primarily by:

- Lower network costs due to avoided network investment ($225 million/a; in red)
- Lower capital cost associated with DE technologies, particularly demand-side options ($84 million/a; in blue)
- Lower fuel and operational costs associated with DE technologies, particularly demand-side options ($51 million/a; cost increase in green, avoided cost in light blue);
- Carbon costs ($76 million/annum at $23/tonne; cost increase in black and avoided cost in orange)

Note that cost savings from displacing existing generation in all scenarios (carbon cost and variable O&M costs) are represented *below zero* on the y-axis. In all scenarios including BAU, existing generation is displaced due to the 20% Renewable Energy Target. In the DE case, the displaced amount is larger than BAU as lower cost DE options are also deployed, offsetting existing generation that has higher marginal costs of operation. While even larger amounts of DE are deployed in the 1600 MW coal retirement case, there is a larger energy shortfall due to the retirement and thus less existing generation is displaced.

Due to some elements being represented as costs (those above zero on the y-axis) and others as benefits or cost offsets relative to the current situation (those below zero on the y-axis), the total final costs for each scenario are shown as a white dash in Figure 29. The total cost (white dash) is the value of the costs (the highest part of the coloured column) minus the value of the benefits or cost offsets relative to the current situation (the part below zero on the y-axis).

The emissions associated with the Least Cost DE Scenario are 3.3 Mt per annum lower than BAU, which translates to a **net benefit** of $110 for every tonne of CO_2 abated. That is, rather than achieving carbon abatement at a societal *cost* for every tonne of CO_2, the DE scenario would actually deliver economic savings concurrently with abatement, to a value of $110 per tonne. The DE Scenario would see Victoria's emissions reduce by 6.2% relative to BAU.

Now drawing on Scenario 3 (1600 MW coal retirement), it can be seen that at a marginal cost of $7 million per annum (Figure 29), or an incremental cost increase for meeting 2020 electricity demands (and renewable energy policy commitments) of 0.8% as compared to the BAU case, emissions could be reduced by 6.5 Mt per annum. The 1600 MW coal retirement scenario would see Victoria's emissions reduce by 12.2% relative to BAU. This translates to an abatement cost of $4 per tonne of carbon dioxide.

Figure 29: Annual cost of supplying energy and capacity shortfalls in 2020 under different scenarios ($2010 billions p.a.)

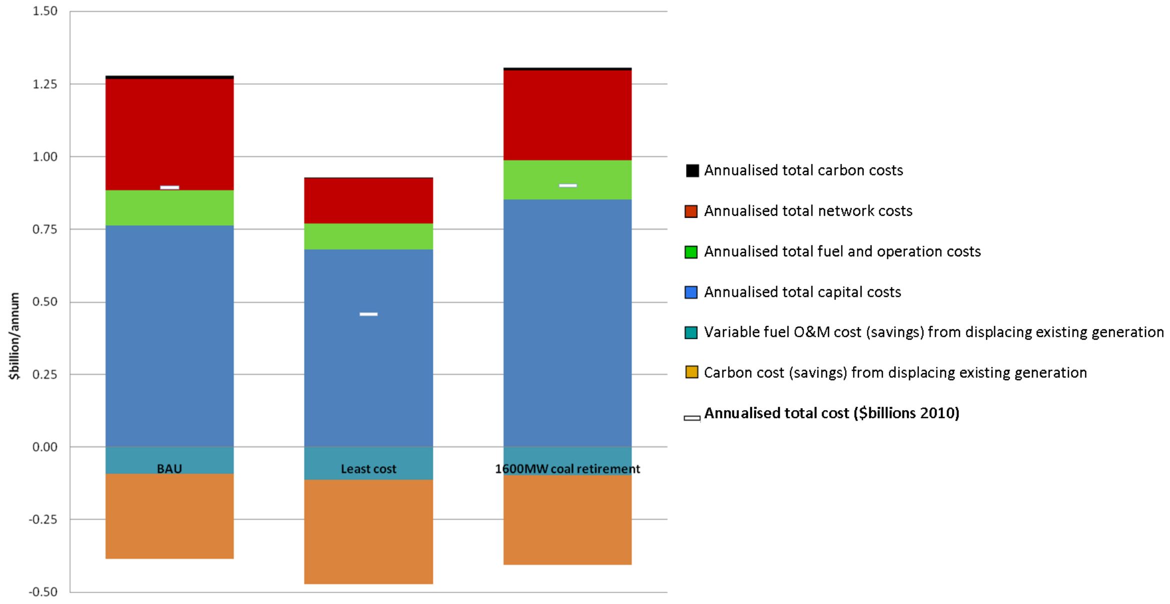
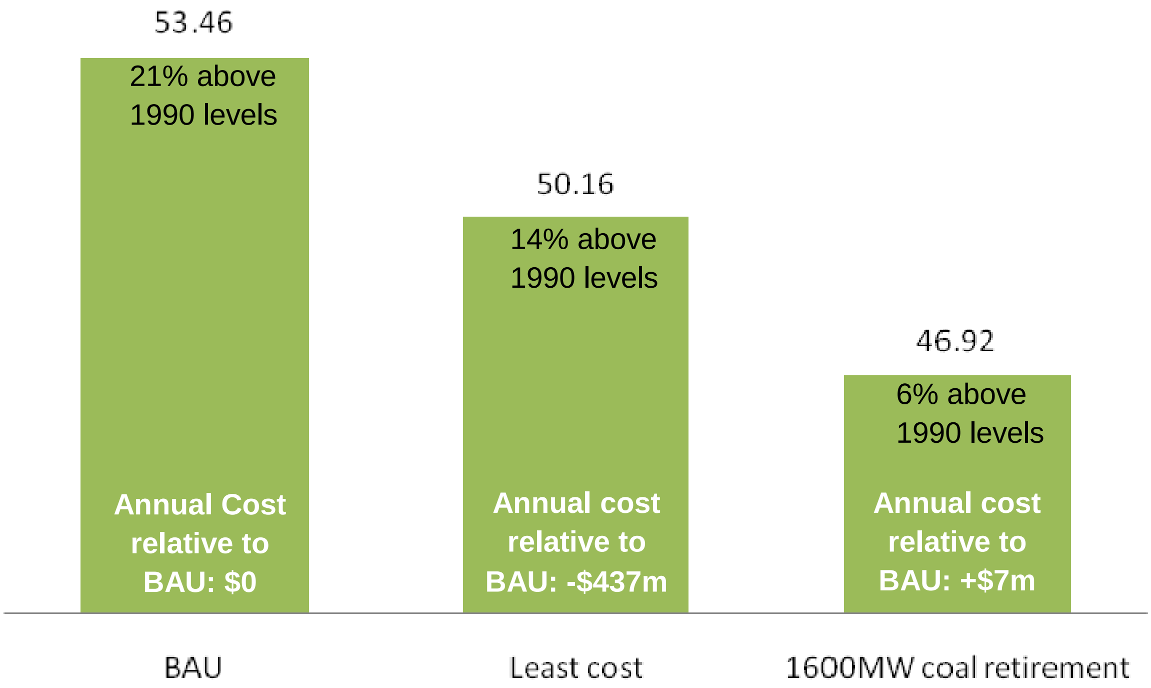


Figure 30: Comparative greenhouse gas emissions in 2020 under different scenarios (Mt CO_2-e per annum)



5.6 Network cost case studies

The D-CODE Model has costs associated with network connection and usage factored in through two means. Firstly, upfront connection costs are included in the capital costs of each particular technology. And secondly, the degree of centralisation of a particular *technology* warrants a Network Cost Factor,[26] which when multiplied by the *jurisdiction's* (in this case Victoria's) default network capital cost,[27] determines the annualised network cost for that specific technology (the red component of the stacked columns in the D-CODE outputs). The Network Cost Factors used for each particular technology are shown in Table 6 below. For cogeneration and trigeneration this value is estimates at 25 percent, meaning that the network cost of connecting the system is 25 percent of the network cost associated with drawing that power from a large centralised coal generator in the Latrobe Valley, for example. Put differently, the network cost of connecting the system is 25 percent of the benefits gained from deferring network augmentation by not using power from a centralised generator. As mentioned in the D-CODE analysis (Section 5), for embedded generators it is intended that the network cost covers any deep connection costs such as augmentation due to fault level issues. Standard connection costs to the grid are included as upfront *capital costs* associated with each technology, not network costs.

In order to cross-check the network cost factors, network cost case studies were investigated in partnership with Citipower-Powercor as part of this research. Two commercial trigeneration proposals were selected by Citipower in discussion with the research team and shallow connection and deep augmentation costs were provided, along with other system details. Shallow connection costs include only those costs exclusively associated with making the new connection, while deep connection costs include additional costs that are indirectly associated with any reinforcement of the system, which could arguably be attributed to all generators on the system (distributed or centralised) (Jenkins et al 2000). These proposals are in different feeder regions within the Melbourne CBD.

As more in-depth data was not available due to confidentiality reasons, a hypothetical cash flow model for these proposals was constructed. This not only allowed a reality check of network cost factors, but also enabled an analysis of how money flows driven by embedded generator network connection affects the key stakeholders: the proponent, the network businesses, other electricity consumers, and the environment. The model is set up to allow users to test for input sensitivity and create scenarios by adjusting key inputs (marked in yellow). A number of scenarios have already been created, and these will be discussed below.

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[26] The average level of non-connection network expenditure warranted by the technology, relative to the default network cost.

[27] Default network cost is the average business as usual cost to deliver centralised energy supply (Langham et al. 2010, Table 35). It is based on the average transmission and distribution costs of upgrading and maintaining capacity in the electricity network to meet growing peak demand.

Table 6: Estimated Network Cost factors (%) for each D-CODE technology/option

Industrial Energy Efficiency	0%	Agricultural Biogas	40%
Commercial Energy Efficiency	0%	Biomass Plant	40%
Residential Energy Efficiency	0%	Wind (offshore)	75%
Residential Hot Water	0%	Wind (onshore)	75%
Commercial & Industrial Demand Management	5%	Solar Thermal (with storage)	75%
Residential Demand Management	5%	Concentrating solar PV	75%
Commercial & Industrial Standby Generation	5%	Ocean (tidal)	75%
Solar PV (grid connected)	5%	Improved Hydro Efficiency	100%
Refuse Derived Fuel (RDF) to energy	40%	Geothermal - Hot Dry Rock	100%
Landfill gas	40%	Combined Cycle Gas Turbine	100%
Sewage gas (Municipal water)	40%	Open Cycle Gas Turbine	100%
Small scale batteries	40%	Supercritical black coal (dry cool)	100%
Industrial Cogeneration	40%	Supercritical brown coal (dry cool)	100%
Commercial Trigeneration	40%	Improved power station efficiency - black coal	100%
Residential Cogeneration	40%	Improved power station efficiency - brown coal	100%
Large scale batteries	25%	IGCC with CCS	100%
Biomass Cogen	40%		

5.6.1 Trigeneration case study assumptions

A summary of the case study details provided is contained in Table 7 below.

Table 7: Case Study data obtained from Citipower-Powercor

	Generator A	Generator B
System size (generation only)	2,495kWe	1,165kWe
Shallow augmentation cost	$205,111	$118,290
Deep augmentation cost	$707,404	$131,210
Upfront network maintenance cost	$29,204	$16,840
Grid connection	Non-exporting	Exporting

A number of assumptions have been used to better estimate the costs and benefits of the systems to the various stakeholders. We have assumed both systems are trigeneration systems, and have modelled the cost, performance (including fuel consumption and electricity avoided) from a trigeneration model ISF has constructed as part of a separate project. These assumptions are provided in Table 8 below.

Table 8: Case Study data estimated from ISF trigeneration model

Name	Generator A	Generator B
System size (inc. cooling offset)	2,900 kW	1,354 kW
Upfront cost	$6,670,000	$3,114,449
FOM cost	$80,000/yr	$37,355/yr
Electricity generated	5,010 MWh	2,339 MWh
Electricity cooling load offset	537 MWh	252 MWh
Gas consumption	83,140 GJ	38,821 GJ
Gas Offset (heating load)	11,594 GJ	5,414 GJ
Gas increase	71,546 GJ	33,407 GJ

5.6.2 Cost and benefits cash flow model embedded assumptions

The cash flow model has numerous inputs for various stakeholders. These are clearly visible and adjustable at the top of each cash flow spreadsheet. Embedded within the model however are some additional assumptions about the direction and circumstances of cash flows which are explained in

Table 9 below.

Table 9: Embedded assumptions within cashflow model

Stakeholder	Row reference	Assumption
All customers	48, 49	Cash flows commence in next regulatory period
All customers	50, 55	All customers forego benefits only if network business operates under revenue cap, and only for current regulatory period
All customers	51, 54	Deferred network capex benefits only accrue if the planned investment occurs beyond the current regulatory period.
DNSP/TNSP[28]	65, 73, 89, 96, 110, 116	Return on capital asset cannot commence in current regulatory period
DNSP/TNSP[28]	83, 104	The network business foregoes revenue only if it operates under price cap, and only for the current regulatory period
DNSP/TNSP[28]	86, 92, 107, 113	No loan is assumed in order to keep the analysis straightforward and clear
DNSP/TNSP[28]	92-95, 113-116	To account for the deferral time, partial years are used for capex, depreciation, value of asset, and return on asset. This is 'real' in the sense that it matches the probabilistic approach to network planning, but may be perceived as inconsistent with DM call for proposals procedures.

[28] Distribution/Transmission Network Service Provider

Stakeholder	Row reference	Assumption
Gas Supplier, Generator and retailer	121-122, 126-127, 131-132	Foregone revenues and costs are limited to the current regulatory period.
Environment	135-137	Environmental costs and benefits are the external costs and benefits that are not borne by the proponent. A public discount rate of 4% is used for the environment; substantially lower than the private discount rate of the proponent. This creates a difference between the public and private net present values, which is accounted for as an environmental cost/benefit.

5.6.3 Network Cost Results

Deferrable (avoidable) network costs

It was assumed that both systems were connected to the same WA Zone Substation (this may not be true in the case of Generator B – please advise). Based on projections from distribution planning reports, WA zone exceeds its firm capacity in 2013, but it is estimated that augmentation would not be required until 2018. At this point it is assumed that an $8 million augmentation is required, estimated based on other similar types of investment in the network. With a demand growth rate of 1.9MVA per year at the zone substation level, this equates to a deferral time of approximately 18 months and 9 months for Generator A and Generator B respectively. Converted to Net Present Value, the current benefit from deferring these investments is $136k and $65k respectively.

At the transmission level, both systems are connected to either WMTS or RTS, which are above firm capacity, leading to a 2014 investment of $170 million (at the BTS terminal station). With a transmission demand growth rate of 46.3MVA per year, this equates to deferrals of approximately 1 month and 0.5 months respectively. Converted to net present value figures, the current benefit to the TNSP from deferring these investments is $840K and $392K respectively. The TNSP's higher deferral value relative to the DNSP is due to a higher investment cost per MVA demand growth, and the earlier investment year.

Network cost factors

The network cost factors can be calculated by dividing the deep augmentation cost by the cost of not deferring network capital expenditure (the benefit of deferring capital expenditure). Shallow augmentation costs are omitted as these are borne by the proponent as an upfront connection cost of installing the trigeneration system. The results under current regulatory conditions are contained in Table 10 below.

Table 10: D-CODE Network cost factor calculations

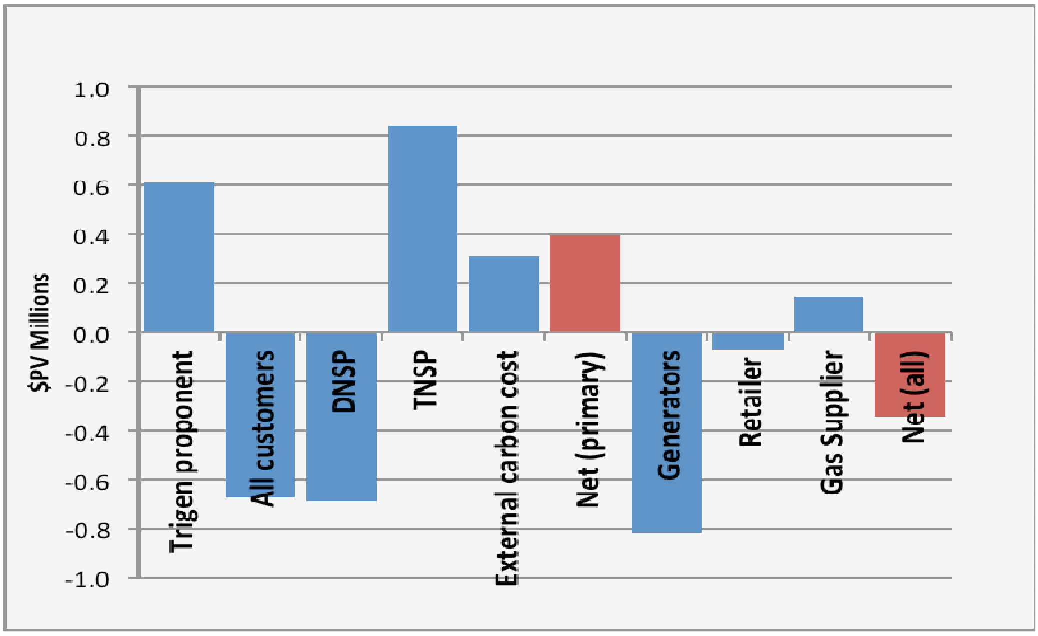
	Generator A	Generator B
NPV deep augmentation	$707,404	$131,210
NPV Deferred Distribution capex	$135,954	$65,145
NPV Deferred Transmission capex	$839,608	$392,041
Total NPV Deferred Network capex	$975,562	$457,186
D-CODE network cost factors	**73%**	**29%**

Compared to the initial estimate of 25 percent used in D-CODE, the Generator B installation aligns relatively closely, while the Generator A installation is substantially higher. Whilst these results suggest an initial underestimate in D-CODE in the case of embedded generators on Victoria's network, a wider sample of connections across diverse geographic areas and network augmentation situations is required to determine a reliable average network cost factor. Nonetheless, for the purposes of the Victorian D-CODE analysis presented in Section 5 of this report, the network cost factor for Distributed Generators was changed to 40 percent (the average of the four scenarios analysed and presented later in Table 11).

5.6.4 Stakeholder analysis

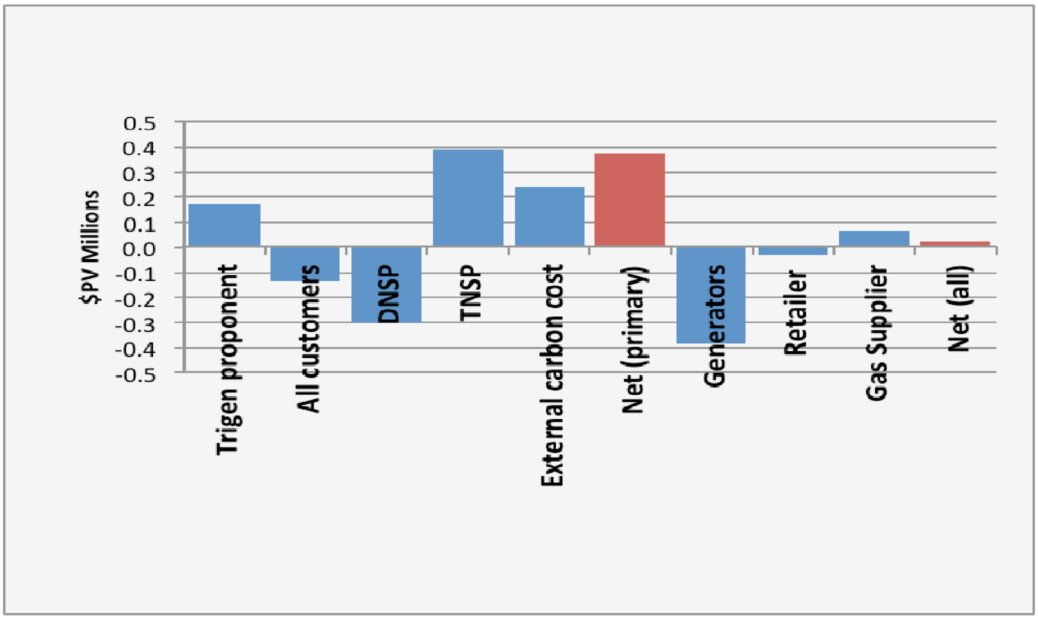
The various stakeholder outcomes are graphed below in Figure 31 and Figure 32. These inputs are based on the current circumstances (scenarios A1 and B1) whereby the DNSP operates under a price cap and the TNSP operates under a revenue cap.[29] The second last column is the net value of all stakeholders combined, whilst the final column is the sum of the primary stakeholders (i.e. those relevant from a policy analysis perspective): the proponent, all customers, network businesses, and the environment. We now discuss the impact on each of the active stakeholders.

Figure 31: Stakeholder outcomes, Generator A (Scenario A1: 2018 augmentation; price cap)



[29] Each scenario has been given an identification number, where A1 stands for Generator A Scenario 1 and B1 stands for Generator B Scenario 1.

Figure 32: Stakeholder outcomes, Generator B (Scenario B1: 2018 augmentation; price cap)



Trigeneration proponent

Installing trigeneration is profitable for the proponent, but the business case is relatively marginal in the modeled scenario above. The net proponent benefits are sensitive to a number of factors, the most sensitive inputs being future electricity and gas prices, the capital cost, the lifespan of the technology, discount rates and interest rates.

All customers

'All customers'[30] are worse off in both cases due to:

- deep augmentation costs being passed on from the DNSP,
- shallow and deep augmentation increasing the return on asset flows to the DNSP
- under the Transmission revenue cap, any reduction in transmission units sold (above the cap) reduces the pass-through benefit in future periods for all customers.

The relatively lower deep augmentation value in the Generator B case substantially reduced the costs to all customers.

DNSP (Network Business)

The DNSP outcomes are summarised below in Figure 33 and Figure 34.

[30] Note that 'All customers' excludes the proponent.

Figure 33: DNSP outcomes, Generator A (Scenario A1: 2018 augmentation; price cap)

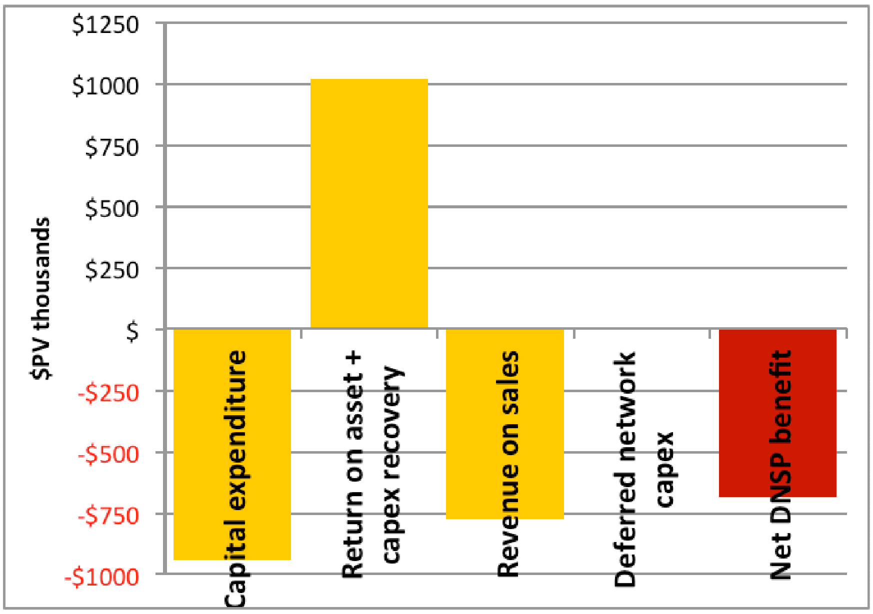
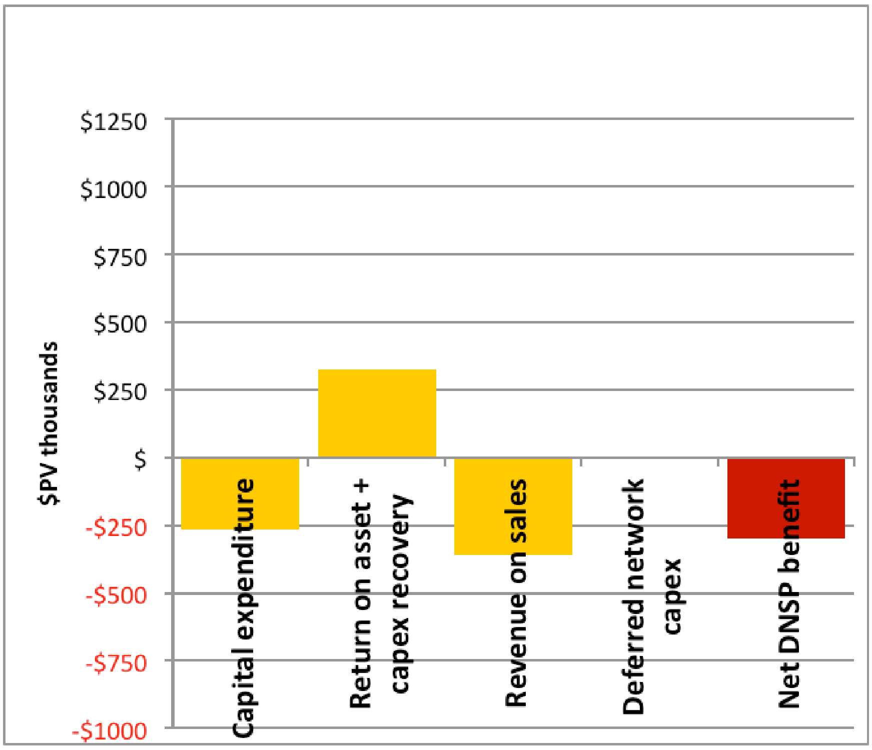


Figure 34: DNSP outcomes, Generator B (Scenario B1: 2018 augmentation; price cap)



In both cases the DNSP incurs a cost from the trigeneration installation. As the capital expenditure (column 1) is more than cancelled out by the subsequent return on asset and capex recovery (column 2), the most costly component in both cases is foregone revenue from reduction in electricity units sold (column 3). If the DNSP was operating under a revenue cap regulatory mechanism, this foregone revenue cost would instead be borne by ‘All customers’, leading to a vastly better outcome for the DNSP, with net impacts close to neutral.

In both cases above, the benefits of deferring network capex (column 4) flow to all customers because the augmentation is scheduled to occur in 2018 and hence AER approval for the planned investment has not yet been sought. Had the planned augmentation been scheduled to occur in the current regulatory period, the benefits would flow directly to the DNSP in column 4.

TNSP

The TNSP is not liable for any deep augmentation costs resulting from the distributed generators, and as the TNSP operates under a revenue cap, it is not disadvantaged by foregone revenue from reduced sales.

As the TNSP is scheduled to undertake an augmentation work in 2014, deferring that augmentation by only a small amount of time leads to substantial present value cost savings, which can be kept by the TNSP as the investment occurs in the current regulatory period. This is due to three factors:

- the value of the expenditure is relatively high;
- the scheduled year of the investment means the benefits of deferring are not heavily discounted (relative to planned augmentation in later time periods); and
- as the investment occurs in the current regulatory period, returns on the asset value cannot be reclaimed until post-2015. This works out favourably for the TNSP as, relative to a non-deferred 2014 investment, greater returns on the asset value are pushed to the post-2015 period and can thus be claimed.

5.6.5 Alternative scenarios

In this section we examine the impact of adjusting some of the input parameters on the key stakeholders. In these specific scenarios, we adjust the DNSP regulatory structure from price cap (as currently applied in Victoria) to revenue cap (as currently applied in Queensland), and also adjust the proposed year of DNSP planned network augmentation. Further sensitivity testing by users is suggested to test the impacts of other inputs on the stakeholder outcomes. The results under current regulatory conditions are contained in Table 4 below. The stakeholder outcomes, including the DNSP breakdown, network cost factor calculations and scenario analyses are summarised in Table 11. The following discussion refers to the scenarios in Table 11.

DNSP Revenue Cap Regulation

The scenarios in Table 11 which apply a DNSP revenue cap are A2 and A4 (for Generator A) and B2 and B4 (for Generator B). These scenarios investigate the trigeneration impact on key stakeholders if the DNSP was operating under a revenue cap regulation instead of the current price cap regulation.

As can be seen in scenarios by comparing A2 (revenue cap) with A1 (price cap), a revenue cap diverts the cost of foregone revenues from less electricity sold (a benefit to the proponent) from the DNSP to All Customers, but does not have an impact on the overall net benefit of each trigeneration system. From this observation, it could be argued that a revenue cap is a necessary prerequisite if DNSPs are to promote the connection of embedded generators. At the same time, it appears that while the net societal outcome is positive, it may be a valid suggestion that all consumers are subsidising the embedded generator, as their costs exceed their benefits in these case studies. This effect is accentuated under a revenue cap scenario unless addressed specifically.

Changing the planned augmentation year

This scenario looks at the hypothetical impact if the connected zone substation was facing an earlier capacity constraint, within the current regulatory period.

Changing the time period of planned network augmentation changes both the scale and the direction of flows stemming from deferred network augmentation. As can be seen in scenarios A3 and A4 (Generator A) and B3 and B4 (Generator B), if the proposed zone substation augmentation was to occur in 2013 as opposed to 2018, the DNSP receives flows that previously accrued to All Customers. Furthermore, the deferral value is significantly greater due to two factors:

- the lesser impact of time discounting; and,
- the investment occurs in the current regulatory time period which means that returns on the asset value cannot be reclaimed until post-2015. This works out favourably for the DNSP as, relative to the original planned investment, greater returns on the asset value are pushed to the post-2015 period and can thus be claimed.

The overall impact is that it substantially boosts the value of trigeneration to both the DNSP and slightly decreases the impact to all customers. It also raises some questions about the network regulatory structure whereby network businesses have a far greater incentive to promote embedded generation if the zone substation augmentation is planned for the current regulatory period. While this does not cause concern at the beginning of a five-year regulatory cycle, at the end of a cycle there is still the disincentive to promote distributed generation, even if the need to defer augmentation is within one or two years.

As can be seen from scenarios A4 and B4, the combined effects of a revenue cap and planned zone substation augmentation in the current regulatory period provide much better incentives for DNSPs to provide incentives for embedded generation such as trigeneration. Without a revenue cap however the NPV of installing trigeneration is negative from the perspective of the DNSP.

Table 11: Scenario analysis results (NPV $2012, millions)

		Generator A				Generator B			
	Scenario id	A1 - current	A2	A3	A4	B1 - current	B2	B3	B4
	Scenario name	DNSP substation aug in 2018 Price cap	DNSP substation aug in 2018 Rev cap	DNSP substation aug in 2013 Price cap	DNSP substation aug in 2013 Rev Cap	DNSP substation aug in 2018 Price cap	DNSP substation aug in 2018 Rev cap	DNSP substation aug in 2013 Price cap	DNSP substation aug in 2013 Rev Cap
Stakeholder outcomes	Trigeneration proponent	$0.6	$0.6	$0.6	$0.6	$0.2	$0.2	$0.2	$0.2
	All customers (exc. proponent)	-$0.7	-$1.4	-$0.8	-$1.6	-$0.1	-$0.5	-$0.2	-$0.6
	DNSP	-$0.7	$0.1	$0.3	$1.1	-$0.3	$0.1	$0.2	$0.5
	TNSP	$0.8	$0.8	$0.8	$0.8	$0.4	$0.4	$0.4	$0.4
	Net (primary stakeholders)	**$0.1**	**$0.1**	**$1.0**	**$1.0**	**$0.1**	**$0.1**	**$0.5**	**$0.5**
	Generators	-$0.8	-$0.8	*-$0.8*	-$0.8	-$0.4	-$0.4	-$0.4	-$0.4
	Retailer	-$0.1	-$0.1	*-$0.1*	-$0.1	-$0.0	-$0.0	-$0.0	-$0.0
	Gas Supplier	$0.1	$0.1	*$0.1*	$0.1	$0.1	$0.1	$0.1	$0.1
	External carbon cost	$0.3	$0.3	*$0.3*	$0.3	$0.2	$0.2	$0.2	$0.2
	Net (all)	**-$0.3**	**-$0.3**	**$0.5**	**$0.5**	**$0.0**	**$0.0**	**$0.4**	**$0.4**
DNSP impacts	Capital expenditure	$0.9	$0.9	$0.9	$0.9	$0.3	$0.3	$0.3	$0.3
	Return on asset + capex recovery	$1.0	$1.0	$1.0	$1.0	$0.3	$0.3	$0.3	$0.3
	Revenue on sales	$0.8	-	$0.8	-	$0.4	-	$0.4	-
	Deferred network capex	-	-	$1.0	$1.0	-	-	$0.5	$0.5
	Net DNSP benefit	$0.7	$0.1	$0.3	$1.1	$0.3	$0.1	$0.2	$0.5
Network Capex	PV deep augmentation	$0.7	$0.7	$0.7	$0.7	$0.1	$0.1	$0.1	$0.1
	PV Deferred Distribution capex	$0.1	$0.1	$1.0	$1.0	$0.1	$0.1	$0.5	$0.5
	PV Deferred Transmission capex	$0.8	$0.8	$0.8	$0.8	$0.4	$0.4	$0.4	$0.4
	Total Deferred Network capex	$1.0	$1.0	$1.9	$1.9	$0.5	$0.5	$0.9	$0.9
	Network cost factor	**73%**	**73%**	**38%**	**38%**	**29%**	**29%**	**15%**	**15%**

5.6.6 Conclusions

These network cost case studies shed some light on the D-CODE network cost factors used for embedded generators and resulted in the estimate being increased from 25 to 40 percent for this Victorian analysis, due to fault level driven augmentation costs. If deep connection costs associated with fault level issues are consistently as high as these case studies suggest, this has **important implications for the way that deep connection costs are calculated and which stakeholder incurs those costs**. Depending on the investment timeframe relative to the regulatory period, it is possible for both the DNSP and the embedded generator to capture benefits from embedded generation at the expense of other consumers. The analysis also shows that regulators need to be aware of sales foregone for network businesses as a result of DE.

Furthermore, the cash flow model provides insight into the impacts of installing trigeneration to the key stakeholders. Perhaps most notably, the scenario analysis conducted using the cash flow model suggests that **switching to a revenue cap would remove a potential disincentive for DNSPs to promote embedded generation** in constrained areas in the form of network support payments.

5.6.7 Areas for further work

This analysis has revealed a host of questions surrounding system fault levels and the impact of embedded generation on “deep augmentation” costs to assist policy makers and the DE industry to better understand these issues and how distributed generators play a role:

- Are these deep and shallow augmentation cost case studies representative of broader industry? A survey with a larger sample of connection cost calculations based on collaboration with network businesses would be of great benefit in answering this question. Further, mapping fault levels in a similar way to that undertaken for the DANCE Model may also be a valuable exercise.
- Are there design configuration options that reduce the liability of embedded generators to deep augmentation costs short of islanding the system?
- Does the current approach to deep augmentation create additional fault level headroom sufficient that particular connection only, or is it more of a 'lumpy' investment somewhat like most other network infrastructure where new capacity is built in larger chunks?
    - If so, does the first connector bear the full cost and later DG connections 'free ride'?
    - Is the deep augmentation in any way "bringing forward" regular augmentation works that would otherwise occur in a future regulatory period?

These questions are important in determining the true liability of embedded generators for network costs, and the associated societal costs and benefits. This also influences the cash flows surrounding new network connections for embedded generators, which is important for policy makers to understand to ensure that all stakeholders – networks, proponents and other consumers – are treated fairly.

6 Quantifying consumer savings from DE

6.1 Introduction

In order to assess the potential impact of reducing network investment through DE on Victorian electricity consumers, an analysis of typical Melbourne CBD electricity tariffs (Citipower network territory) for three customer types has been undertaken to determine the proportion of tariffs and bills made up by network charges. This is the tariff component that can be reduced through the large-scale deployment of DE to alleviate network constraints more cost-effectively.

Specifically, the analysis breaks down current (2011) retail tariffs into the following components:

- Wholesale electricity contract costs
- Distribution charges
- Transmission charges
- Federal Renewable Energy Target (RET)
- Victorian Feed-in Tariff, known as a "Jurisdictional Scheme" pass-through cost
- Metering charges
- Retail costs
- Retail margin

Note that distribution and transmission charges are often bundled together as total network charges; however, for this report they have been kept separate as avoided network costs from Decentralised Energy apply differently to Distribution and Transmission expenditure. The analysis includes a breakdown of the average delivered unit cost of electricity (c/kWh) and the breakdown of a representative bill in each customer class. Appendix A provides the assumptions, sources and detailed data-tables associated with this analysis.

The purpose of this analysis is to provide an indicative baseline for the likely impact on Melbourne customers of proposed network upgrades and to project potential savings associated with undertaking decentralised energy options. The three customer types and their representative annual energy consumption levels are:

- Residential Customers – 5,500kWh p.a. (approximate Victorian average household consumption)[31]
- Small to Medium Businesses – 20MWh p.a. (representative of a small to medium sized 'High St' business, such as a real estate agent)[32]

[31] Based on 2007 Average Household consumption in Victoria of 5,533 kWh/a from Roy Morgan Research (2008)
[32] Note that regulators in other States often use consumption of 10-12MWh p.a. for small business.

- Large Business – 1,000MWh p.a. and a peak demand of twice the average demand. (representative of a commercial office with gross floor area of ≈4000m^2) with average efficiency performance.[33]

The analysis uses network pricing for the CitiPower distribution area only, to reduce complexity as per the scope of works. Standing offer retail prices for single rate flat-tariff customers in the CitiPower distribution area have been used for residential and small-medium business customers, as published in the *Victoria Government Gazette* in December 2010 to come into effect on 1 January 2011. Retail rates were averaged for AGL, Origin Energy, EnergyAustralia, Red Energy, Lumo and Simply Energy, so as not to bias according to one particular retailer. Published 2011 CitiPower network pass-through charges for single rate flat tariff customers have also been used. All large business tariff components and the remainder of the components of the bills have been inferred from a range of sources, as this data is not explicitly in the public domain due to Victoria's unregulated retail electricity market. These sources and assumptions are provided in Appendix A.

6.2 Average unit electricity cost (cents per kWh)

Electricity prices have both **volumetric components** (those parts of the bill linked to each kilowatt hour (kWh) of electricity consumption) and **standing charges** (those parts of the bill charged as fixed fees per customer or per meter per year) or in the case of large business, **demand charges** (those parts of the bill charged according to the highest kilowatt (kW) instantaneous demand across the year at the customer's site).

This analysis takes *all* of those charges and computes the total bill for each customer type at the representative consumption level described above. It then divides the total annual bill by the total consumption in kWh per year, to produce figures in cents per kWh for each bill component. This enables a more accurate picture of the overall contribution to the average unit cost of electricity. It must be noted not to confuse this analysis with straight analyses of the volumetric (per kWh) components of the bill, which *exclude* standing or demand charges.

Figure 35 provides a breakdown of the average unit cost of electricity for the three customer classes of interest. For all three customer classes wholesale energy costs make up the single largest component, contributing between 5 and 7 c/kWh. Wholesale contract prices used are based on a range derived from 2004-2006 data in CRA (2007) and differ by 30 percent according to customer class. The level of certainty over the assignment of the larger residential wholesale purchase contract price is considered greater than for small and large businesses. Note that these figures are 40-80% higher than average Victorian electricity market spot prices, which reflects the retailer costs associated with hedging against market price volatility and weighting of wholesale contracts according to the timing of demand in

[33] For a basic guide to office energy consumption see Exergy (2011).

each customer class relative to peak periods. These prices align fairly closely with the recently released AEMC pricing analysis (AEMC 2011, p.65). For full assumptions see Appendix A.

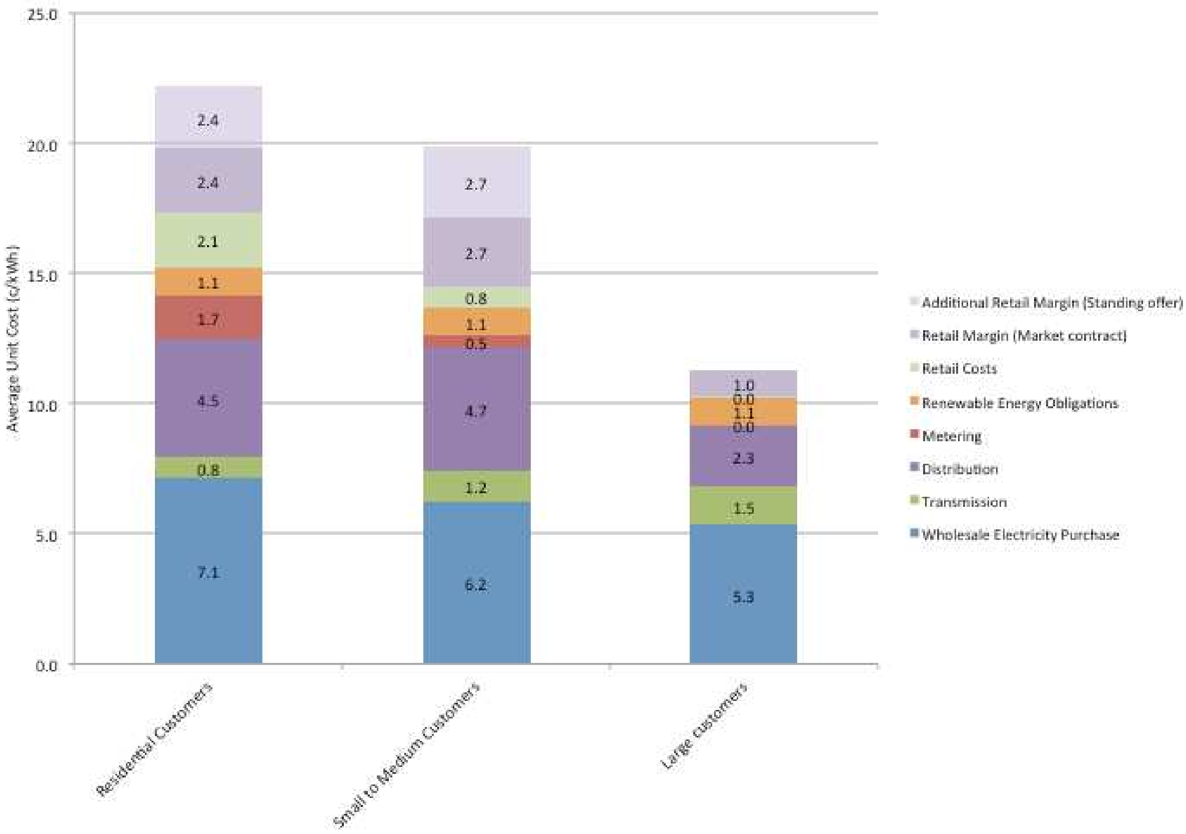
Network charges, including both distribution and transmission components make up the next most significant contributor, at around 5 to 6 c/kWh for the two smaller customer classes[34] and 3.8 c/kWh for large business. The final most significant contributor is the retail margin,[35] which makes up 2.4-2.7c/kWh in market contracts for the smaller customer classes, and a further 2.4c/kWh (totalling 4.8ckWh) for standing offer contracts. This is because market contracts have lower prices, and given the same cost outlay for retailers, the retail margin is smaller in this more competitive environment. For this reason the contract and standing offer retail margins have been represented in Figure 35 for the smaller customer classes as solid and semi-transparent mauve boxes respectively. This reflects the fact that many customers are on market contracts and will not pay the full retail margin. Note that large customers only show a basic contract retail margin as there are no published "standing offer" retail tariffs for this class as these customers are all on market contracts.

In Figure 35 the Federal (RET) and State (feed-in tariff) schemes have been combined into a single category called "renewable energy obligations", which makes up a relatively small proportion of the total for the smaller customer classes, and a more significant proportion of the large customer average unit price. The contribution shown here for 2011 is higher than expected in subsequent years due to the Federal government "multiplier" upfront payments for small-scale renewable energy installations, which progressively reduce over time.

[34] The residential figure in this analysis is within 1-2% of later published AEMC (2011) findings. However, note that for Victoria as a whole the AEMC network charges component is 23% higher than for Citipower alone due to inclusion of other networks where network costs are proportionally larger.

[35] Retail costs + margin is around 15% lower than AEMC residential estimates. As the retail margin is determined by the balance once all other components are worked out (in both this report and AEMC 2011), the main reasons for the discrepancy are our higher estimate of renewable energy obligations, based on ROAM (2011).

Figure 35: Citipower 2011 average electricity cost by component (c/kWh including standing/demand charges)



6.3 Breakdown of typical customer bills

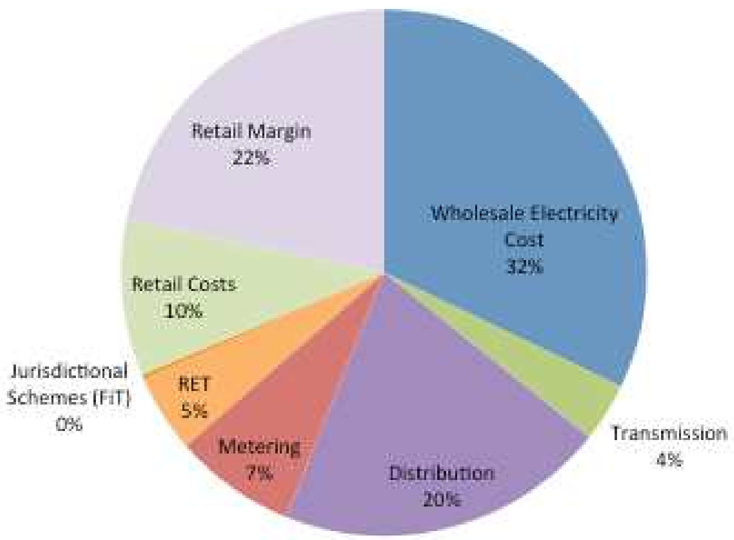
Breakdowns of example customer bills are also provided for the three customer classes.

6.3.1 Residential Customers

Figure 36 indicates that for an average annual residential electricity bill of a 5.5kMWh/a home on a standing offer, wholesale electricity costs make up just under one third, while distribution and transmission costs account for just under a quarter. This translates to $392 and $293 respectively of a $1,221 bill (see Appendix A for all figures). The retail margin makes up 22% of the standing offer bill under current conditions, although this figure would likely be smaller for residential customers on market contracts. Renewable energy obligations such as the Renewable Energy Target and state Feed-in Tariff (FiT) contribute around 5% of the total, at $61 per year.

Figure 36: Breakdown of an Average Melbourne Residential Electricity Bill (Standing Offer, Citipower network area)

Assumes average household usage of 5,500 kWh p.a.



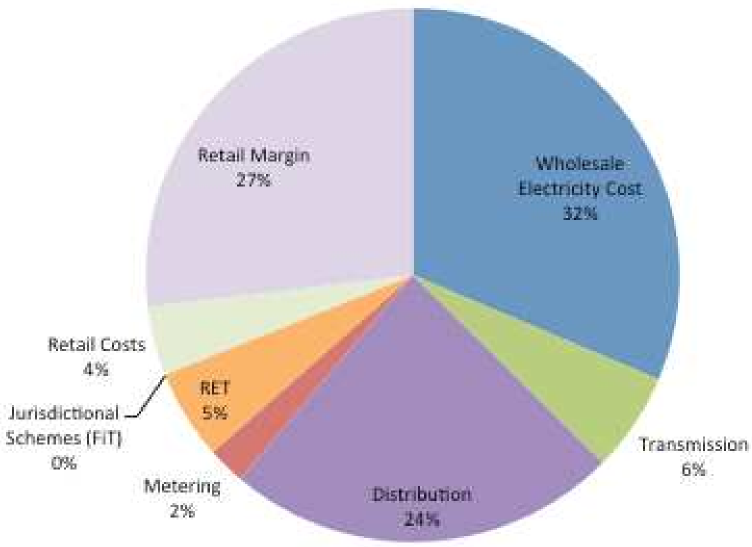
ISF's residential analysis has been compared with Victorian electricity price data from a recent ROAM Consulting report (2011, Table 1.2) and were found to be similar for small components, while ISF attributes a larger proportion to wholesale energy costs, and a smaller proportions to retail costs and margin as well as network costs.

6.3.2 Small to Medium Businesses

Figure 37 indicates that for an average total annual small to medium business electricity bill ($3,968), just over a third is made up of wholesale electricity costs ($1,246). Network charges and retail components both make up around 30%, at $1,177 and $1,233 respectively. Again, the retail *margin* component of this would be expected to be lower for market contracts than for standing offers. Renewable energy obligations make up around 7% of the total bill; at around $217 per annum (see Appendix A for full figures).

Figure 37: Breakdown of an Average Small to Medium Business Electricity Bill (Standing Offer, CitiPower network area)

Assumes average business usage of 20MWh p.a.

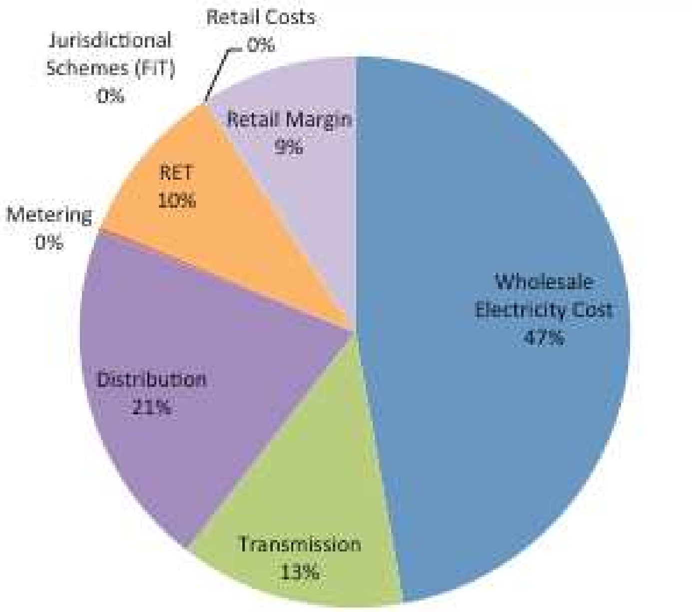


6.3.3 Large Customers

Figure 38 indicates that for a large business electricity bill of 1000MWh/annum ($122K), wholesale energy costs are the largest component at just under half ($53K) even when assuming the lowest end of the contract price range. This is followed by network costs at just over a third of the total bill ($38K). As this is a market contract, the retail margin was guided by ranges given in CRA (2007) as discussed above, which are less than half of the margins under standing offers. Using an assumption of 10% of total revenue, this yields a retail margin of just over $10K. This estimate carries the lowest level of certainty amongst the figures in this pricing analysis as information in the public domain is limited and subject to negotiation by individual parties. It is assumed that the RET costs are passed on to Large Customers at the same unit rate as smaller customers, as exemptions are only available for Emissions Intensive Trade Exposed Industries by application to the Office of the Renewable Energy Regulator. Using this assumption yields a relatively high proportional cost of renewable energy obligations at 10% ($11K). The Victorian FiT is not passed-through to this customer class, while retail costs are a very small proportion.

Figure 38: Breakdown of an Average Large Business Electricity Bill
(Market Contract, CitiPower network area)

Assumes average business usage of 1,000MWh p.a.



6.4 Reductions in customer bills from Decentralised Energy

Section 5 outlined the following three scenarios:

1. Business as usual ('BAU': includes 20% Renewable Energy Target).
2. Decentralised Energy deployment ('DE': includes 20% Renewable Energy Target; based on lowest cost deployment of *all* technologies but with consideration of network costs).
3. Coal Retirement: As per Scenario 2 with end-of-life retirement of 1600 MW of coal fired power generation capacity.

For the purposes of determining potential customer savings, we compare Scenarios 1 (BAU) and 2 (DE) (For more detail on scenarios see Section 5. The DE scenario uses lowest cost deployment of technologies to meet Victoria's projected peak capacity shortfall in 2020 (noting that there is no predicted *energy* (kWh) generation shortfall out to 2020). The "Optimal Mix Analysis" undertaken for Scenario 2 using the DCODE Model included the following deployment of Decentralised Energy technologies:

- 1001 MW peak capacity / 5,027 GWh p.a. of Energy Efficiency
- 664 MW peak capacity of Peak load Management
- 0 MW peak capacity of Distributed Generation (DG is not deployed as higher in the cost order than other DE alternatives for the given capacity shortfall)

This is a significant departure from the BAU scenario, which sees primarily the use of centralised fossil fuel generation apart from the renewables mandated by the RET. To assess the potential impacts on consumer bills of deploying this amount of DE, the following impacts need to be considered:

1. ***Price* component reductions:**
    a. Savings in **electricity network charges** due to reduced infrastructure spending resulting from DE deployment. These avoided network capacity costs total $294 million per annum[36] by 2020 but only result in customer price reductions in the regulatory period 2016-2020, as under a price cap regulatory structure network businesses capture any capital savings from DE deployment in the current regulatory period (2011-2015). The savings do, however, reach consumers in subsequent periods, providing the regulator factors in reduced network spending due to lower rates of peak demand growth from cost-effective DE deployment. Net savings are slightly lower than the $294m p.a. network spending reduction, as the cost of DE measures must be attributed to relevant components of the bill. We

[36] In $2020. This was been inflated to $2020 figure for the purposes of the nominal tariff analysis at a rate of 2.7% p.a., and in $2010 corresponds to the $225m p.a. savings from the DE Scenario.

assume that network businesses bear and pass on the annualised cost of peak load management measures ($45.6m in 2020), such as through a Collaborative Targets and DE Fund model.[37]

b. Savings in **energy generation costs:** There are likely to be energy generation price reductions resulting from reducing price spikes in the National Electricity Market, although these market effects are difficult to quantify and thus have not been assessed in this study.

2. *Price* component increases:

a. ***Network Prices:*** Fixed expenditures on infrastructure – that are repaid by being spread across all electricity sales – increase in price when they are spread across the lower volume of electricity sales resulting from energy efficiency being part of DE deployment. Network prices go up by the percentage of energy reductions achieved.

b. ***Retail Costs:*** The $143.8m of energy efficiency costs are attributed to retailers and passed through to customers in the volumetric retail costs component, as would be the case through the extension of a white certificates scheme.[38]

3. *Volume* reductions:

a. **Savings in full retail rates** (which include savings in generation,[39] network and retail costs) due to customers purchasing less kWh of electricity, which result from customers participating in end-user energy efficiency activities. This results in a 1.6% reduction in residential energy consumption,[40] a 6.3% reduction in commercial (small and large business) consumption and 18% reduction in industrial consumption[41] (not included as a customer class in our tariff analysis). These figures translate to a 9.5% reduction in total electricity consumption in Victoria.

b. **Avoided carbon costs:** These total $76 million per annum in 2020 at $23 per tonne of carbon dioxide. Carbon price projections are not included in the BAU pricing scenario, and thus carbon savings are included as an

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[37] These costs may be an overestimate, as the network will only need to expend the cost of the incentive to facilitate that demand reduction.

[38] These costs may be an overestimate, as the retailer will only need to expend the cost of the incentive to facilitate that energy reduction.

[39] This refers to savings in generation capital and operational costs due to capital costs/savings and reduced fuel and operational expenditure (eliminating the need to build and operate as many power stations). According to the D-CODE analysis, these savings total $135 million per annum in 2020 and are inherently passed on to consumers through the volume effect (reduced consumption).

[40] This is a conservative figure, as the D-CODE energy efficiency figures do not include low cost behaviour change (inadequate data available – it is planned to include this in later revisions of the model).

[41] This is based on a national estimate of industrial energy efficiency potential from Energetics (2004) estimate scaled according to Gross State Product of Victoria. While this estimate is quite high, it is the most reliable data source found by the research team. It is recommended that further research be undertaken on the market potential for industrial energy efficiency in Australia.

additional $/customer figure, associated with the amount of reduced energy consumption of that customer class.

6.4.1 Average Impact of Network Prices

To assess the net impact of competing price reductions (1a) and increases (2a) on average network prices, a high-level analysis is conducted for all customers. The average network charge across all customer types is calculated by diving total revenue of Victorian network businesses (distribution and transmission)[42] by the total volume of electricity sales. This performed using expected 2011 revenues, which yields an average figure of 4.33c/kWh in 2011. Escalated to 2020 with price increases and inflation, this works out as 7.48c/kWh. The network price *increase* as a result of a 9.5% reduction in consumption is 9.5%, or 0.71c/kWh. The price *reduction* from reduced network expenditure of $294 million (in $2020) – if we also assume that the network bears and passes on the annualised cost of peak load management measures ($45.6m in 2020), such as would happen under a Collaborative Targets model[43] – equates to 0.53c/kWh (7.1%). The c/kWh increase less the c/kWh reduction nets out to an average network price increase of 0.18c/kWh, or 2.4%. These calculations are shown in Table 12.

Table 12: Calculation of *average* network price impact in 2020 from DE

BAU Average Network Price in 2020	7.48 c/kWh
Average Network Price change due to energy demand reduction	+0.71 c/kWh
Average Network Price change due to reduced network spending	-0.53 c/kWh
Net Network Price impact in 2020 (c/kWh)	+0.18 c/kWh
Net Network PRICE impact in 2020 (%)	**+2.4%**
Net VOLUME change counteracting increase (%) (although applies to full retail rate rather than just network component)	**-9.5%**
Net Network BILL change from DE	**-7.1%**

6.4.2

[42] Total expected 2011 revenues were $1.56b for distribution and $0.5b for transmission from AER (AER 2010a, pp.828-831)

[43] refer to the Australian Decentralised Energy Roadmap (ISF 2011).

6.4.3 Average Impact on Consumer Bills

To estimate the average impact on customer bills, it is necessary to estimate the total revenue from retail electricity sales in Victoria, including all customers. This data is not readily available, however it is possible to make an estimate from reported NEM figures. The 2009-10 NEM wholesale energy market turnover was $9.6 billion (AER 2010, p.19) and as energy costs make up around 40% of total retail charges,[44] the total sales revenues of the NEM were likely in the order of $24 billion in 2009-10. As Victoria makes up 24% of national energy consumption,[45] this translates to total revenue of $5.8 billion in 2009-10. If we assume a 24% real retail price rise to 2020 (the price rises embedded within the simple tariff analysis later in this report), this takes total revenues up to $8 billion in 2020. Introducing a carbon liability of 1.04kg CO_2-e/kWh (Victoria's modelled intensity in D-CODE in the 2020 BAU scenario) adds a further $1.3 billion, yielding a grand total Victorian electricity cost in 2020 of $9.3 billion.

As the DE Scenario saves $437m ($0.437b), this translates to an average saving in customer bills of 4.7%. This total reduction in bills is despite the average retail price rising by 5.3% to account for the lower volume of energy consumption.

6.4.4 Consumer Bill Impacts by Customer Type in 2020

This section now analyses what the above price and volume impacts might look like on a range of average customer types. If we assume the full deployment of DE by 2020 as per Scenario 2, the savings by average customer in each of the customer class types analysed in the earlier tariff analysis are shown in Table 13 below.

Table 13: Customer bill changes in 2020 from DE Deployment ($/customer/annum) [#]

	Residential	Small-Medium Business	Large Business
Price effect	+$0.85	+$103.08	+$5,440.76
Volume effect	-$22.88	-$340.25	-$10,609.62
Carbon cost	-$2.09	-$30.03	-$1,501.32
TOTAL CHANGE	**-$24.12 (-1.3%)***	**-$267.20 (-4.3%)***	**-$6,670.18 (-3.5%)***

*Notes: # - Positive numbers represent an increase in bills and negative numbers represent a decrease in bills; * - Percent change in total annual bill including carbon liability.*

[44] The AER calculates a range of 37-45% (AER 2010, p.98)
[45] Based on 2009-10 actual consumption of Victoria relative to the NEM in AEMO (2011, p3-8, 3-23)

The underlying drivers for the figures shown in Table 13 are now discussed in relation to each customer class.

Residential Customers: Residential customer bills are reduced in the DE scenario by $24, or 1.3%. The net price effect results in a small bill *increase* of $0.85 per customer per annum. This is a combination of a +0.15c/kWh network price change as a result of reduced consumption of 1.6% in the residential sector, a -0.53 network price change due to reduced network spending,[46] and +0.39c/kWh retail cost price change[47] associated with operating an energy efficiency obligations scheme.

With reduced consumption of 1.6%, the volume effect reduces bills by $22.88. The carbon saving associated with this volume reduction adds another $2.09. The amount of energy reduced in the residential sector is small as a reasonably limited amount of cost-effective residential energy efficiency measures was assumed in D-CODE based on available data sources. D-CODE did not include some of the cheapest but difficult to quantify residential energy efficiency measures, such as those resulting from behaviour change.

The combined price and volume effects for residential customers result in a 1.3% reduction in the final bill in 2020, reducing from to $1845.91 p.a. to $1870.04 p.a..

Small-Medium Business Customers: Small-medium business customer bills are reduced in the DE scenario by $267, or 4.3%. The net price effect results in a bill *increase* of $103 per customer per annum. This is a combination of a +0.65c/kWh network price change as a result of reduced consumption of 6.3% in the commercial sector, a -0.53 network price change due to reduced network spending, and +0.39c/kWh retail cost price change[47] associated with operating an energy efficiency obligations scheme.

With reduced consumption of 6.3%, the volume effect reduces bills by $340. The carbon saving associated with this volume reduction adds another $30 of customer savings.

The combined price and volume effects for small-medium business customers result in a 4.3% reduction in the final bill in 2020, reducing from to $6228 p.a. to $5960 p.a..

Large Business Customers: Large business customer bills are reduced in the DE scenario by $6670, or 3.5%. The net price effect results in a bill *increase* of $5441 per customer per annum. This is a combination of a +0.39c/kWh network price change as a result of reduced consumption of 6.3% in the commercial sector, a -0.53 network price change due to reduced

[46] Network price reductions are assumed to occur at the same magnitude as the energy demand reductions in each sector. This results in a small cross-subsidy of smaller customers from larger customers.
[47] 0.39c/kWh was applied evenly to all three customer classes. This was not expressed as a percentage as it is misleading as the contribution of this small component was markedly different in each customer class.

network spending,[48] and +0.39c/kWh retail cost price change[47] associated with operating an energy efficiency obligations scheme.

With reduced consumption of 6.3%, the volume effect reduces bills by $10,610. The carbon saving associated with this volume reduction adds another $1501 of customer savings. Note that the volume effect for this customer class includes reductions in both volumetric and demand charge components of the final bill as a result of reduced consumption.[49]

The combined price and volume effects for large business customers result in a 3.5% reduction in the final bill in 2020, reducing from to $188,235 p.a. to $181,565 p.a..

6.4.5 Consumer Bill Impacts by 2015

While not quantified and analysed in detail, it is worth noting the impact on customers under the DE scenario by 2015. Positive and negative transmission network price changes will be passed on to consumers as the transmission network is subject to revenue cap regulation. Positive and negative distribution network price changes will not be passed on to consumers until after 2015, as the these networks are subject to a set price cap regulation until the end of the current regulatory period. Energy efficiency price increases (if charged as a levy bundled into retail costs) are likely to be passed on to the extent that energy reductions have been implemented by this time. Likewise, approximately half[50] of the 2020 volume effect savings shown in Table 13 above would benefit those residential, small, medium and large business customers that have undertaken energy efficiency measures. Underlying this point is that the above analysis is for customers in those classes *on average.* In reality there will be distributional effects meaning that:

- participants in energy efficiency activities (and potentially time of use tariff arrangements) will benefit due to their volume reductions outweighing price increases; while
- non-participants those that do not participate will be affected by price increases, without the benefit of volume reductions. This creates an unintended, but perhaps not unimportant, additional incentive for participation in energy efficiency activities that is not quantified in this study.

[48] The same average c/kWh network saving was applied to all three customer classes, but the relative impact on each class was different due to the different magnitude of network tariffs by customer class, therefore c/kWh was used for the explanation instead of percentages.

[49] The pricing model assumes a peak demand twice that of the average demand for this customer class. As total electricity demand is reduced through energy efficiency, the peak demand is thereby implicitly reduced pro rata by the relevant amount.

6.4.6 Impact on Network Businesses in 2015

It is worth analysing the relative financial position of Victorian network businesses in 2015, when their regulatory conditions are "reset" for the coming five-year period. The annual savings to network businesses from infrastructure spending resulting from an incremental deployment of DE[50] are $99 million in 2015. The reduced revenue for these businesses is the network component of 2,241 GWh of reduced sales in 2015 (4.5% of total sales). This could represent a combined revenue reduction of up to $123 million,[51] placing distributors' net financial position $24 million worse off than in the BAU case.[52] Therefore the AER must be mindful of sales foregone for network businesses not otherwise recoverable under other regulatory mechanisms such as the Demand Management Incentive Scheme (DMIS). Alternatively, changing from a Price Cap to a Revenue Cap regulation system would remove this disincentive for distribution businesses to facilitate energy efficiency. This decision would need to be made by the AER two years prior to the initiation of the 2016-2020 regulatory period (by 1 January 2014).

6.4.7 Summary

This analysis suggests that the lowest cost application of Decentralised Energy options[53] will deliver savings to Victorian consumers in the order of 4.7% of average bills. However, this occurs from a complex interaction of price and volume effects, which on average translate to modest price increases, but a greater magnitude of reduced consumption (lower volume). These calculations work out differently for different customer classes, but hinge strongly on the amount of energy efficiency undertaken within that sector. This stems from the fact that:

- Energy efficiency delivers both peak demand and volume reductions, and as such *raises prices*, but *lowers volumes* by a greater amount and thus *lowers bills*. Emissions are also strongly reduced;
- Peak load management measures deliver *price reductions and bill reductions* by reducing network infrastructure investment *without* reducing sales volume (energy consumption) or carbon emissions (generally); and
- Distributed generation (although not part of Scenario 2) delivers peak demand reductions and will deliver billing volume reductions *if* offsetting a customer's demand. Whether or to what extent prices are raised as a result of DG depends on whether local load is being offset, and the credit that the network gives the DG provider for its services. Emissions are also reduced.

[50] It is assumed that an incremental straight-line deployment of DE occurs between 2011 and 2020.
[51] At an average nominal 2015 network price of 5.5c/kWh.
[52] Based on combined 2015 distributor revenue of $1.9 billion (AER 2010, p.832). Note that what is shown is a simple pro-rata volumetric calculation and does not factor in demand charges and how these are impacted by Demand Management measures. Such a calculation is beyond the scope of this analysis.
[53] This specific analysis included energy efficiency and peak load management measures but did not include distributed generation as it was not deployed in the D-CODE lowest-cost analysis.

Note also, however, that this analysis is restricted to the assessment of flat tariff structures. As the electricity sector heads towards more cost-reflective price structures, flat tariffs will become less prevalent. DE measures – even those that do no reduce consumption but which shift demand to off-peak times – such as those that give consumers greater ability to control when and how they use power, will therefore reap additional benefits in a time-of-use pricing based environment.

Given that the majority of consumer benefits are associated with the reduction of consumption through energy reduction, it is important to recognise that consumers will primarily benefit as participants in energy efficiency activities. Thus if all consumer sectors are to benefit, care must be taken by policy makers in addressing institutional barriers to the uptake of energy efficiency, to ensure that cost-effective residential, commercial and industrial energy efficiency opportunities are tapped.

Also note that in other jurisdictions, electricity price reductions will be far more significant due to the greater spending on network infrastructure. It must be remembered that while electricity prices are important, this is only half of the picture, as it is electricity bills that matter to consumers.

7 Conclusions

This research indicates that there is substantial untapped cost-effective potential of DE in Victoria, which if implemented strategically, stands to reduce electricity sector emissions by 6.2 percent and save electricity consumers $437 million per annum by 2020-21. Consumer benefits are delivered through modest network charge increases relative to Business-as-Usual being more than offset by more substantial volumetric reductions associated with lower electricity consumption.

Furthermore, tackling challenges such a gradual retirement of coal-fired generation as they reach the end of their economic life are found to be manageable with DE options in the sectoral mix. DE increases the range of options to tackle future peak capacity and energy generation shortfalls in a more dynamic, cost effective and flexible fashion. Victoria is well placed to initiate and develop more flexible processes towards adopting DE in network development, as it already operates on a probabilistic network planning model and instituting similar processes for DE application is a small step from current practices relative to other States which are based on deterministic investment triggers.

Through the delivery of customised DANCE and D-CODE Models for Victoria, this research provides valuable tools for policy makers, electricity network businesses, and DE industry service and technology providers to identify the optimal timing and location of DE opportunities, to progressively build a functional and responsive Demand Management industry in Victoria.

While Victoria currently faces one of the lower marginal costs of new network supply in the country, this research raises questions about the future direction of electricity network expenditure in Victoria, given its somewhat anomalous situation. Victoria may in fact be well placed to act in advance of other states, before Victoria's strong summer peak demand growth drives more substantial new network expenditure and price pressures on electricity consumers, to avoid the problems seen in NSW and Queensland.

8 List of supporting information

The following outputs have also been produced as part of this Scope of Works:

A. DANCE graphical output images:
   a. **DANCE_Victoria.kmz** (Google Earth format)
   b. **Proposed Investment_Melbourne.jpg** (Image file)
   c. **Proposed Investment_Ballarat.jpg** (Image file)
   d. **Proposed Investment_Bendigo.jpg** (Image file)
   e. **Proposed Investment_Geelong.jpg** (Image file)
B. DANCE Model GIS Layers:
   a. **DANCE_GIS_Files.zip**

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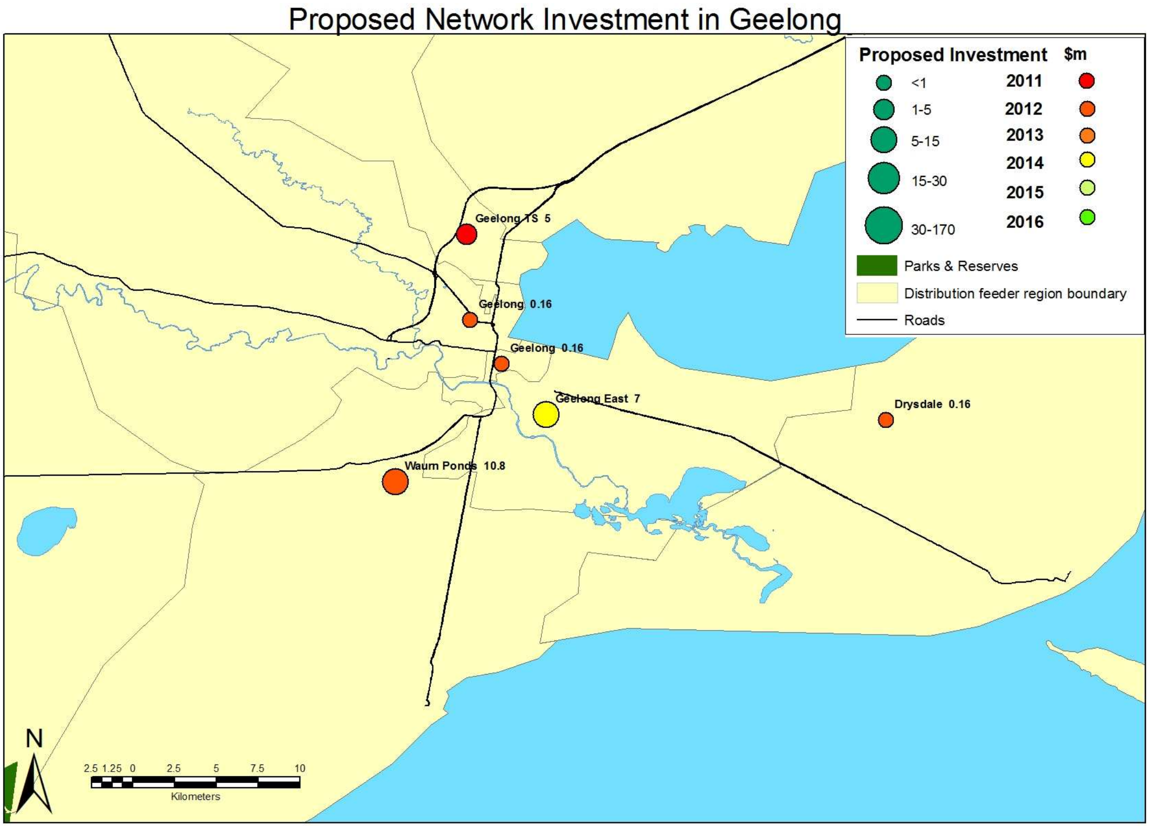
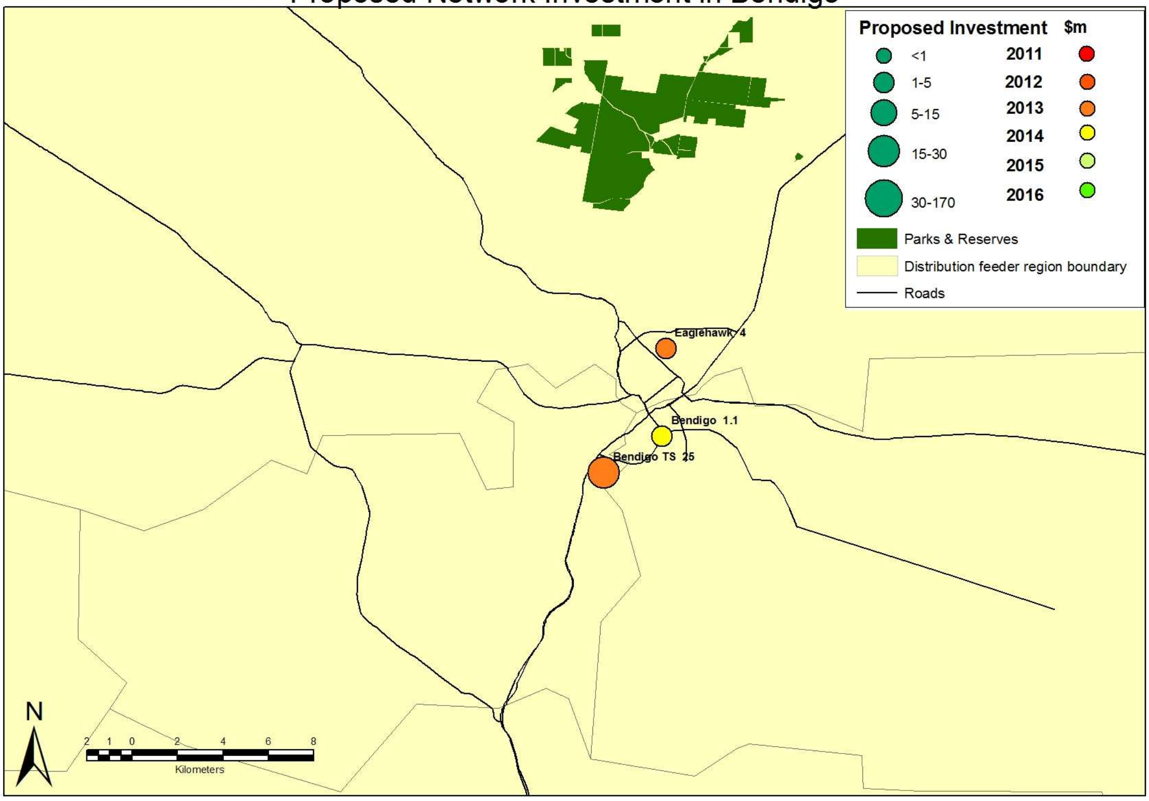
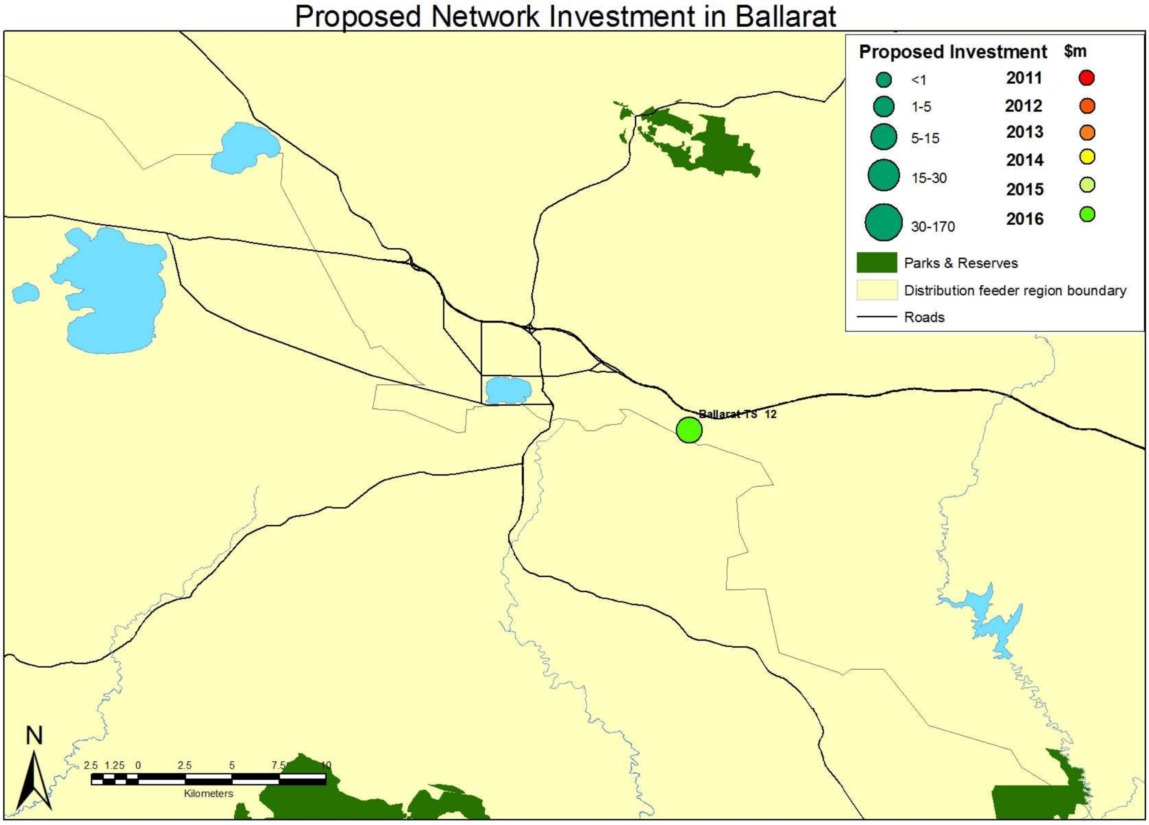
Appendix A: Proposed Investment Images – Geelong, Bendigo, Ballarat



Proposed Network Investment in Bendigo



Proposed Network Investment in Ballarat



Appendix B: Stand-Alone DANCE Map User Instructions

DANCE Map User Instructions

Background

Sustainability Victoria (SV) commissioned the Institute for Sustainable Futures (ISF) to look at the potential opportunities, costs and benefits for Decentralised Energy (DE) in Victoria, particularly in the context of reducing electricity network investment. The primary output of this work is the production of **time-series maps** for Greater Melbourne, Geelong, Bendigo and Ballarat that highlight 'hotspots' in both time and space where DE could potentially be applied most cost-effectively by deferring network investment. These maps turn annual reporting and other simple network planning data that is currently of limited usefulness to those unfamiliar with the technical details of network planning, into simple but powerful interactive visual outputs for **policy makers and regulators** needing to understand the dynamics of where and how DE can contribute to beneficial economic and environmental outcomes, and to **networks and DE service providers** who need to know or communicate the geographical areas in which the greatest benefit from DE products and services can be obtained.

This short guide gives a brief, stand-alone explanation of how to interpret these images and their embedded information. For more context see Section 4 of the accompanying report. The user will first need to:

1. Download the DANCE Map file from the SV website entitled: **DANCE - Victoria.kmz**
2. Download Google Earth from: www.earth.google.com (free)
3. Have access to a fast internet connection to enable Google Earth to download imagery

Basic Instructions

When Google Earth is installed on your computer, double click on the file

'**DANCE - Victoria.kmz'**

This will open Google Earth and zoom to Australia and the image "Available Capacity" will be overlayed, as shown by the ticked box next to "Available Capacity" in the 'Places' box on the left of the screen (if this is not visible, expand the menu by clicking on the grey triangle next to "DANCE – Victoria"). Zoom in to Victoria or the specific sub-region of interest. The user can turn image layers on and off to toggle between the Available Capacity and the different Deferral Value images contained within the file. The user can also turn other layers such as roads ON or OFF from the 'Layers' section beneath 'Places' on the left of the screen, and adjust the transparency of any layer to show the underlying satellite imagery, by using the slide bar between Places and Layers. Roads are initially turned OFF to allow the user to view the time series at the State/city level. When interrogating smaller regions of interest it is recommended to turn the Roads layer ON.

Each DANCE image is a time series from 2010 to 2015. This can be controlled using the time slider bar in the top left of the map. The boundaries between coloured zones in each map are the distribution zone substation feeder region boundaries. These are based on Sustainability Victoria region maps from 2007 with some manual zone updates by the research team, and thus do not exactly reflect the current feeder region boundaries where changes have been made over this period. Nonetheless, these boundaries are relatively accurate for the vast majority of zones.

Available Capacity

This is essentially a map of 'firm capacity' according to the relevant reliability criteria (commonly *n-1*),[54] minus the forecast peak demand. This allows the user to see the progression of load growth relative to distribution zone substation capacity over time. **Note that these images show available capacity *before* network or non-network options are taken to alleviate constraints.** This is not an image of areas facing power outage.

The green and yellow colours indicate distribution zones that have sufficient spare capacity in 2015 (available capacity is above zero), while the pink and red colours (where available capacity is below zero) indicate distribution zones facing growth-related constraints where investment will be needed to ensure reliability is maintained. Note that while many zone substations are above their firm capacity for much of the time series, this reflects Victoria's network planning methods, which dictate that available capacity should become negative before investment in network upgrades is made. This commonly translates to demand exceeding firm capacity by around 10 MVA (i.e. available capacity reaches -10 MVA) before investment is made, which is why there are numerous light pink (-5 to 0 MVA) and medium pink (-15 to -5 MVA) areas.

Clicking on a specific region will reveal the details of that region, including the season of constraint and the exact available capacity value for each year.

Annual Marginal Deferral Value

Taking into account the planned investment at distribution, sub-transmission and transmission levels (refer to Figure 13 in accompanying report – this figure is not available as a Google Earth layer) and the rate of growth driving that investment, we produce maps showing Annual Marginal Deferral Value (expressed in $/kVA/year). These maps show the effective cost of addressing constraints through the preferred network solutions. This annual value is essentially an upper bound to the amount that could be spent on non-network options to alleviate a constraint: if less than this amount is spent addressing the constraint using non-network options such as distributed generation, peak load management or energy efficiency, then overall the cost to networks and consumers is lower. However, these maps do not consider any additional network costs, such as those associated with addressing fault level issues in the case of distributed generation. In this case these costs would reduce the value of this type of DM to the network. Further, DM options are generally considered by

[54] *n-1* refers to reliability criteria whereby supply is still maintained when one transformer or supply line is out of service.

network businesses to be less reliable than network options, which may also be reflected in the amount that networks are willing to pay DM providers for their services.

Areas in grey are those with no deferral value. Areas in yellow are those with limited deferral value that is less than the approximate average cost of network service provision (the average cost of network service provision is approximately $235/kVA/year. Marginal deferral value increases strongly in the areas where the pink colour intensifies ($400-1000/kVA/yr), which are the areas where DM can be highly attractive. The best opportunities for DM are those zones shown in purple, where the values are greater than $1000/kVA/yr. **For a detailed example of how an embedded generator would apply the annual deferral values see** Figure 15 **in the accompanying report.**

Using the time slider, note that by 2015 many of the DM opportunities are shown to have disappeared. This is because the investment planned for many of those regions has been spent, eliminating the possibility of deferral. What these images do not show, however, is that there would be new network investments appearing each year with every updated network planning report. Given that we do not yet know where these are going to be, they cannot be mapped and thus the annual marginal deferral value shows far less opportunities in 2015 than in 2010.

When the user clicks on the distribution feeder region, a range of additional information is shown in a white information box. An explanation of the additional information is given below:

- **ZS_Code** = The shorthand code used by distribution businesses to refer to this zone substation.
- **ZS_Name** = The full name of the distribution substation asset servicing this feeder region
- **Asset_Type** = Whether the network asset is at the Distribution, Sub-Transmission or Transmission level.
- **Longitude/Latitude** = Geographic coordinates of the zone substation (NB: some have been moved from their precise location for the purposes of this GIS analysis).
- **Network** = Distribution business operating that zone
- **Pk_Season** = the primary season of constraint likely to drive network investment.
- **Constraint** = the initial season where available capacity becomes negative (usually the same as Pk_Season, but in some cases may be “Both” – this case indicates that there is load at risk in both seasons but that overall the Pk_Season has been classed as the dominant season).
- **Dx_Inv_Yr** = the year of planned investment at the Distribution zone substation level.
- **Dx_GrwthRt** = the annual demand growth rate driving any distribution investment (MVA/yr).
- **SubT_Inv_Yr** = the year of planned investment at the sub-transmission level.
- **SubT_GrwthRt** = the annual demand growth rate driving any sub-transmission investment (MVA/yr).
- **Tx_Inv_Yr** = the year of planned investment at the Transmission Terminal Station level.
- **Tx_GrwthRt** = the annual demand growth rate driving any transmission investment (MVA/yr).

- **Total_2011 = TOTAL Annual Marginal Deferral Value in $/kVA/yr (distribution + transmission + sub-transmission). This is the value reflected by the colour of the zone.**
- **Distn_2011** = DISTRIBUTION Annual Marginal Deferral Value ($/kVA/yr)
- **SubT_2011** = SUB-TRANSMISSION Annual Marginal Deferral Value ($/kVA/yr)
- **Trans_2011** = TRANSMISSION Annual Marginal Deferral Value ($/kVA/yr)

Note that if a particular zone is selected and the time slider bar is used, the user will need to reselect the zone to see new information embedded only within the image of a different year. Also note that at the time of writing in late 2011, any network investments planned for 2012 (as shown in Dx_Inv_Yr, Tx_Inv_yr or SubT_Inv_Yr) or earlier are likely to be committed and therefore become unavoidable. Thus the annual images of most importance or 2013 and beyond.

Monthly Marginal Deferral Value

The Monthly Deferral Value layer goes further by breaking down the annual deferral value into the months in which those constraints occur, to start to more clearly articulate the seasonal variation underlying network constraints.

The monthly deferral values shown are based on the exceedance of capacity in the first year of constraint, which differs for each substation.[55] This ensures that any annual deferral values that occur over the 2010-2015 time horizon of DANCE are registered in the images.

The category classes are the same as for annual deferral value, only the units differ, this time in $/kVA/month instead of per annum. As constraints often only happen in one or two key months per year, the summer or winter monthly $/kVA values are of the same magnitude as the annual $/kVA values, while other months generally show deferral values close to zero. Note that almost all of the constraints occur in summer (January), and Victoria has very few solely winter-peaking substations.

Hourly Marginal Deferral Value

The Hourly Deferral Value layer breaks down the deferral value into hourly timeslots on the key peak days in which those constraints are occurring, which indicates the types of electrical loads driving the constraints and reveals the times of day during which DM must reduce loads.

Again, the category classes are the same as for the annual and monthly deferral value maps, only the units differ, this time in $/kWh – the most common unit of energy billing. This analysis reveals that even in constrained zones with moderate deferral value of say $400/kWh, this is 2,000 times the ~$0.20/kWh value that a typical residential customer on a flat tariff is actually paying for power at that time. In zones where this tops $1000/kWh this

[55] This means that for some substations 2010 may be represented, while others may show 2015.

translates to over 5,000 times the flat tariff rate. While these deferral values only apply to those specific limited peak hours throughout the year, it demonstrates the inability of current time of use tariffs (at $0.40/kWh) to send a pricing signal that would influence consumers to reduce demand.

Further information

For more information on the calculation methodology underlying these maps and the study from which these outputs was produced, see the accompanying report:

Langham, E., Dunstan, C., Cooper, C., Moore, D., Mohr, S. and Ison, N. 2011, *Decentralised energy costs and opportunities for Victoria*, prepared by the Institute for Sustainable Futures, University of Technology Sydney for Sustainability Victoria, November 2011.

Appendix C: Melbourne Electricity Tariff Analysis – Data and Assumptions

Table 14: Volumetric unit energy cost breakdown

	Residential		Small to Medium		Large		
Electricity price 2010/11 used for calculations	**c/kWh**	**%**	**c/kWh**	**%**	**c/kWh**	**%**	
Wholesale energy price	7.13	40%	6.23	34%	5.33	61%	Estimates based on average market contract price range from 2004-2006 as found in CRA (2007, Table 5), when wholesale spot price in the NEM were similar to 2008-2010 (current prices). i.e. $53.3-71.3/MWh. Residential contract values were assigned the highest contract price due to peaky demand, which was confirmed to be in the appropriate range by industry feedback (Shires 2011). Large customers were assumed to be at the bottom end of the contract price range due to more predictable load pattern and larger purchase volumes, while small-med business was selected as the mid-point between these values. These rates represent increases of 40-80% on average AEMO spot prices (http://www.aemo.com.au/data/avg_price/averageprice_main.shtml) last visited 24/5/2011.
Transmission	0.74	4%	1.15	6%	1.31	15%	CitiPower Transmission & Distribution Tariff Schedule 1 Jan 2011 - 31 Dec 2011, Tariff Code C1R Residential, C1G Non-Residential, C2DL Large Low Voltage. Two tier block tariffs are weighted according to total annual consumption of the relevant customer type.
Distribution	4.23	23%	4.53	25%	1.00	11%	
SRES	0.59	3%	0.59	3%	0.59	7%	ROAM Consulting (2011) - Table 8.1, p31 (2011) cost of STC on retail tariff. Assumed SRES passed onto Large consumers (exemptions only for EITES http://www.orer.gov.au/eites/index.html)

LRET	0.48	3%	0.48	3%	0.48	6%	ROAM Consulting (2011) - Table 6.2, p19 (2011) cost, with a shortfall charge of $65/MWh. Assumed LRET passed onto Large consumers (exemptions only for EITES http://www.orer.gov.au/eites/index.html)
Retail costs & margin	4.87	27%	5.25	29%	0	0%	Back-calculated from tariff and other components. For large business this is calculated on the final bill.
Total (GST exclusive)	**18.04**	**73%**	**18.24**	**71%**	**8.71**	**100%**	**Average of all retailers (excl. TRU Energy) for residential and SMEs. Large not published**

Table 15: Standing or capacity charges breakdown

	Residential		Small to Medium		Large		
Electricity price 2010/11 used for calculations	**c/day**	**%**	**c/day**	**%**	**c/kW/day**	**%**	
Transmission	1.03	2%	2.27	3%	2.29	1%	CitiPower Transmission & Distribution Tariff Schedule 1 Jan 2011 - 31 Dec 2011, Tariff Code C1R Residential, C1G Non-Residential, C2DL Large Low Voltage
Distribution	4.35	7%	9.80	11%	15.77	10%	
Jurisdictional Schemes (FiT)	0.80	1%	0.80	1%	0.00	0%	
Metering charge	25.04	40%	25.04	28%	98.17	61%	
Retail costs	32.05	51%	45.21	51%	45.21	28%	$75 + customer acquisition costs of $42 for residential and $90 for small & large business (CRA, 2007 Tables 12 and 13)
Retail margin	-0.52	-1%	4.79	5%	0.00	0%	Back-calculated from tariff and other components. For large customers calculated on total bill at 10% of total (upper end of margin on Market Contract with Low Wholesale Prices).
Total	**62.75**	**100%**	**87.91**	**100%**	**161.43**	**100%**	**Average of all retailers (excl. TRU Energy)**

Table 16: Total electricity bill breakdown ($/annum)

	Residential		Small to Medium		Large	
Assumed annual electricity consumption	**5,500**	kwh/pa	**20,000**	kwh/pa	**1,000,000**	kwh/pa
				Peak Demand	**228.31**	kW/pa
Component						
Wholesale Electricity Cost	**$392.15**	32.1%	**$1,246.00**	31.4%	**$53,300.00**	47.2%
Transmission	**$44.40**	3.6%	**$238.09**	6.0%	**$15,001.17**	13.3%
Distribution	**$248.63**	20.4%	**$942.72**	23.8%	**$23,150.53**	20.5%
Metering	**$91.38**	7.5%	**$91.38**	2.3%	**$358.32**	0.3%
RET	**$58.85**	4.8%	**$214.00**	5.4%	**$10,700.00**	9.5%
Jurisdictional Schemes (FiT)	**$2.93**	0.2%	**$2.93**	0.1%	**$-**	0.0%
Retail Costs	**$117.00**	9.6%	**$165.00**	4.2%	**$165.00**	0.1%
Retail Margin	**$265.86**	21.8%	**$1,068.14**	26.9%	**$10,267.50**	9.1%
Total Bill	**$1,221.20**	100%	**$3,968.26**	100%	**$112,942.52**	100%

Table 17: Average per unit electricity breakdown (c/kWh)

	Residential	Small to Medium	Large
Component			
Wholesale Electricity Purchase	**7.1**	**6.2**	**5.3**
Metering	**1.7**	**0.5**	**0.0**
Transmission	**0.8**	**1.2**	**1.5**
Distribution	**4.5**	**4.7**	**2.3**
Renewable Energy Obligations	**1.1**	**1.1**	**1.1**
Retail Costs	**2.1**	**0.8**	**0.0**
Retail Margin (Market contract)	**2.4**	**2.7**	**1.0**
Additional Retail Margin (Standing offer)	**2.4**	**2.7**	**0.0**
Total Bill	**19.8**	**17.2**	**11.3**

Appendix D: Assumptions for Victorian Decentralised Energy Potential

Technology or program	Classification	Description	Capacity potential assumptions
Industrial Energy Efficiency	Energy Efficiency	A variety of energy efficiency measures undertaken by industrial energy users across multiple industries.	National figure from Energetics (2004), p. 68 table. Based on investments with less than 4-year payback. Conversion from PJ to MWp using assumed CLF of 65%. Scaled to states using GSP (ABS Cat no. 5220.0)
Commercial Energy Efficiency	Energy Efficiency	Energy efficiency measures undertaken by commercial energy users in areas including: the Energy Star program, lighting, heating and cooling, pumping and air handling.	Langham et al. (2010). Based on the peak demand reduction of a variety of energy efficiency measures (moderate scenario). Least cost effective measures were not included in analysis.
Residential Energy Efficiency	Energy Efficiency	Cost effective reduction in electricity consumption through improvements such as insulation and draught sealing, lighting, hot water demand reduction.	Langham et al. (2010). Based on the moderate scenario. Least cost effective measures were not included in analysis.
Residential Hot Water	Energy Efficiency	Converting electric domestic hot water systems to electric boosted solar, heat pump and gas.	Langham et al. (2010). Based on the accelerated scenario. Assumptions: 60% of technical potential is achieved with before-end-of-life-replacement. 33% of capacity is from electric to gas switch. 33% is from solar electric boost replacement and 33% is from heat pump replacement. Summer peak capacity.

Commercial & Industrial Demand Management	Peak Demand Management	Commercial and industrial customers are provided incentives at times of peak demand to shed or interrupt their load or shift their load to times of lesser demand.	NSW figure provided by Ross Fraser, Energy Response (2009). Pers. Comm. Additional capacity estimate in 2020. Conservative estimate. Scaled to states and nation using GSP (ABS Cat no. 5220.0).
Residential Demand Management	Peak Demand Management	Residential customers are provided with information and/or incentives to shed or interrupt their load peak demand or shift their load times of lesser demand. Achieved through widespread dynamic time of use pricing (as opposed to static TOU pricing), combined with moderate adoption of programmable communicable thermostats (PCT).	Federal Energy Regulatory Commission (2009). Residential MWp Modelled peak load reduction in California by 2020, scaled to Australia by GDP. Converted from MWp to MW using firm peak rating of 95%. Scaled to states using residential electricity demand figures in Langham et al. (2010)
Commercial & Industrial Standby Generation	Peak Demand Management	Commercial and industrial customers are provided incentives to turn on their standby generators during demand peaks.	NSW estimates from Demand Management and Planning project (2008) final report and DEUS (2005). NSW estimates from studies: [278MVA (Energy Australia) + 42MVA (Integral) + 6MVA (Country) converted to MW using power factor of 1]. Scaled to states using GSP (ABS Cat no. 5220.0)
Industrial Cogeneration	Cogeneration (and Trigeneration)	Gas turbine at an industrial facility, where in addition to using the electricity generated, the useful heat is used for industrial heating loads.	Sustainability Victoria (2010)

Commercial Trigeneration	Cogeneration (and Trigeneration)	Gas turbine at a commercial site, where in addition to using the electricity generated, the useful heat is used for heating loads. D-CODE data includes the electricity generation component and the demand reduction component.	Sustainability Victoria (2010)
Residential Cogeneration	Cogeneration (and Trigeneration)	Gas turbine in a residential area, where in addition to using the electricity generated, the useful heat is used for heating loads (Medium-large multi unit dwellings – 50-100 apartments per complex – centralised hot water and cogeneration). D-CODE data includes the electricity generation component and the demand reduction component.	ISF estimate. Scaled from national figure using population, then weighted according to climate. Weight=1.35. Scaled up to include demand reduction by multiplying by 1.224 (ISF calculations).
Refuse Derived Fuel to Energy	Bioenergy	Electricity generated from non-recyclable wood waste, paper and plastic	ISF estimate based on the estimated 20 million tonnes of non-recyclable waste per year, of which paper (19%), wood (8%) and plastics (9%) could be utilised for energy generation. Based on rollout of 40% of potential. Scaled to states using population.
Agricultural Biogas	Bioenergy	Electricity generated by burning biogas produced from agricultural sources, such as digesting livestock waste.	Clean Energy Council (2009). Anaerobic digestion/reciprocating gas engine, direct combustion and pyrolysis techniques for poultry, cattle, pigs, dairy cattle; abattoirs). National figure scaled to state using population

Biomass Plant	Bioenergy	Electricity generated by burning biomass, specifically forestry and sawmill residues and energy crops such as camphor laurel, oil mallee, eucalyptus and Enercane.	Clean Energy Council (2009). Includes mostly forestry and sawmill residues, but also oil mallee / eucalyptus and enercane (energy crops), and camphor laurel. Scaled to state using land area committed to timber plantations (DAFF 2007)
Biomass Cogen	Bioenergy	Burning biomass, specifically sugar cane bagasse, where in addition to using the electricity generated, the useful heat is used for heat processing.	Clean Energy Council (2009). Pulp and paper mill cogeneration
Landfill gas	Bioenergy	Energy from capturing and burning methane released from decomposition of landfill waste.	Clean Energy Council (2009). National figure scaled using population
Sewage gas (Municipal water)	Bioenergy	Energy from capturing and burning gas collected from sewage treatment plant bio-digesters.	Clean Energy Council (2009). National figure scaled using population
Improved Hydro Efficiency	Renewables	Various measures to improve the efficiency of existing hydroelectric power stations.	Includes 50% of current Snowy Hydro modernisation figures (other 50% assigned to NSW) + potential upgrade to other existing capacity (ESAA 2010), multiplied by average capacity upgrade potential of 6% from EPRI (1999) Table 2.2.

Wind (offshore)	Renewables	Energy from wind is harnessed through large grid connected turbines, located up to several kilometres offshore.	European Wind Energy Association (2010). Half of Europe's offshore wind target of 10% of total capacity by 2020, applied to Australia's current 50GW installed capacity. Scaled from national using average state distribution weightings for onshore wind from 3 studies; Access Economics 2009, KPMG 2009, and Carbon Market Economics 2009
Wind (onshore)	Renewables	Energy from wind is harnessed through large grid connected turbines, located on land.	Carbon Market Economics (2009). Upper estimate (assumes less non-wind mix in RET). Scaled from national using average spatial distribution weighting for onshore wind from 3 studies; Access Economics 2009, KPMG 2009, and Carbon Market Economics 2009.
Solar Thermal (with storage)	Renewables	Mirrors concentrate energy from the sun onto a focal point or tube filled with liquid. This liquid produces steam to drive a turbine. Salt cells can store heat to provide electricity on demand.	Black and Veatch (2006). 10-year California high deployment scenario projections, Table 4.1 p21. Note: 1) California has equivalent summer peak and annual energy generation to Australia; 2) California has 33% RET by 2030). Scaled from national figure using ISF estimate of 12% of national potential within this state
Concentrating solar PV	Renewables	Mirrors concentrate and reflect sunlight onto high efficiency solar photovoltaic cells to produce electricity.	TBC
Solar PV (grid connected)	Renewables	Energy from the sun is harnessed through grid connected photovoltaic power systems.	BSW-Solar (2010). Growth of solar PV installations in Germany 2000-2009 (part 7), adjusted for Australia's population. Scaled from national figure using population, then weighted according to climate. Weight=0.85

Geothermal - Hot Dry Rock	Renewables	Heat stored in low permeability rock below the earth's surface is harnessed by circulating water through drilled or naturally occurring fissures and using the returned superheated steam to generate electricity.	MMA (2010). Based on projections for generation in the expanded RET. Scaled from national figure using ISF estimates. First plant online in 2017.
Ocean (tidal)	Renewables	Large turbines are positioned underwater to take advantage of regular tidal flows (wave energy is not included in this analysis).	ISF Estimate. Assumes tidal power installed in Northern Australia where large tidal ranges occur.
Large scale batteries	Energy Storage	Sodium Sulphur Battery - High Temp battery (molten sulphur and molten sodium). Suitable for applications between 10 and 100MW. Stand alone units used for peak shaving and often used to balance loads of power plants such as wind	Doughty et al. (2010). Potential in Australia is assumed to be the current installed capacity in Japan, which has a majority of the global installed capacity. Scaled from national figure using population.
Small scale batteries	Energy Storage	Flow Batteries (Vanadium Redox, Zinc Bromine). Similar in operation to hydrogen fuel cell. Suitable for applications between 100kW and 10MW normally in association with peaky power plants such as wind or solar	ISF estimate
Combined Cycle Gas Turbine	Centralised Fossil	Internal combustion jet turbine, powered by natural gas, with waste heat converted to additional electrical energy by steam turbines	ISF estimate

Open Cycle Gas Turbine	Centralised Fossil	Internal combustion jet turbine, powered by natural gas	ISF estimate
Supercritical black coal (dry cool)	Centralised Fossil	Turbine produces electricity from steam at supercritical temperatures. The steam is produced in a boiler by combusting pulverised black coal.	ISF estimate
Supercritical brown coal (dry cool)	Centralised Fossil	Turbine produces electricity from steam at supercritical temperatures. The steam is produced in a boiler by combusting pulverised brown coal.	ISF estimate
Improved power station efficiency - black coal	Centralised Fossil	Various measures to improve power station efficiency of existing black coal fired power stations.	Sinclair Knight and Mertz (2000). Calculated from 2% CO2 reduction figure, applied to existing black coal capacity.
Improved power station efficiency - brown coal	Centralised Fossil	Various measures to improve power station efficiency of existing brown coal fired power stations.	Sinclair Knight and Mertz (2000). Calculated from 3.3% CO2 reduction figure, applied to existing brown coal capacity.
IGCC with CCS	Centralised Fossil	Internal gasification combined cycle technology with carbon capture and storage. Black coal is gasified and combusted to generate electricity, and emissions are pressurised and pumped into underground geologic features.	ISF Estimate, assume technology is first available in 2017