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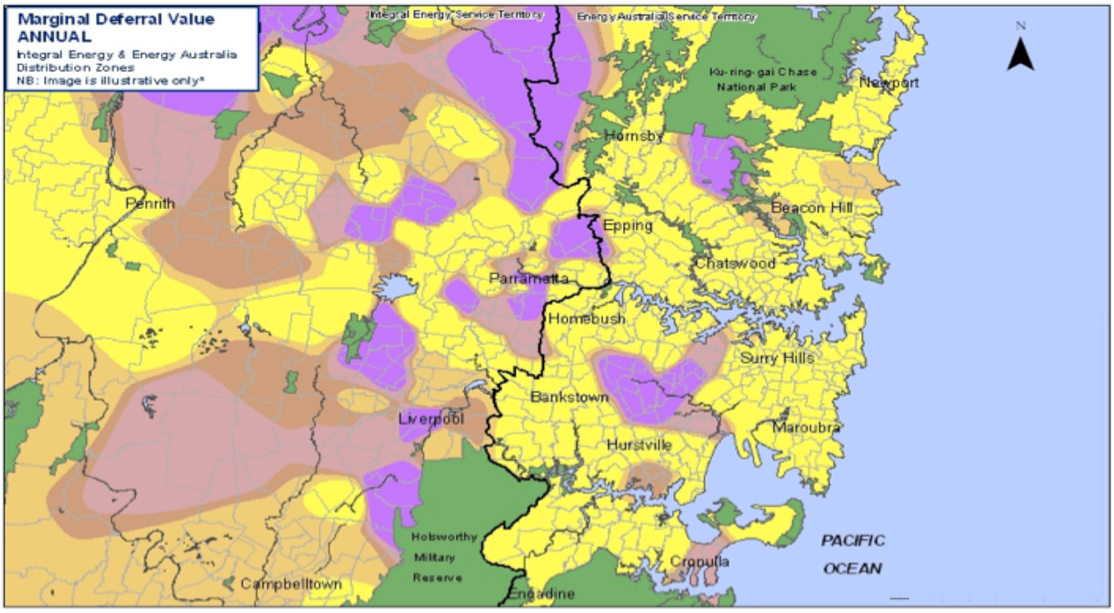
iGrid Project 4:

Institutional Barriers, Economic Modelling and Stakeholder Engagement

Mapping Network Opportunities for Decentralised Energy: The Dynamic Avoidable Network Cost Evaluation (DANCE) Model



Working paper 4.4

November 2011

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Mapping Network Opportunities for Decentralised Energy: The Dynamic Avoidable Network Cost Evaluation (DANCE) Model

Intelligent Grid Research Program
Project 4

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Institute for Sustainable Futures

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Intelligent Grid Working Papers

Engaging with stakeholders is a key element of the Intelligent Grid Research Program. In order to encourage dialogue and collaborative learning, a series of working papers is being published during the course of the three-year program. It is intended that these working papers will be revised and reissued from time to time as the research and consultation proceeds. Stakeholders are invited to comment on and contribute to the development of these working papers. At the conclusion of the program, the working papers will be formalised as final reports.

The working papers for Project 4 include:

4.1. Institutional Barriers to Intelligent Grid (ver.1 published June 2009, ver.2 November 2011)

4.2. 20 Policy Tools for Developing Distributed Energy (ver. 1 published November 2009, ver.2 November 2011)

4.3. Evaluating the Costs and Potential of Decentralised Energy (ver. 1 published November 2009, ver. 2 November 2011)

4.4. Mapping Network Opportunities for Decentralised Energy: The Dynamic Avoidable Network Cost Evaluation (DANCE) Model (this paper; published November 2011)

4.5. Deliberative processes Distributed Energy development (published November 2011)

The Australian Decentralised Energy Roadmap (published December 2011)

Submissions invited

This working paper aims to examine the current and proposed costs associated with developing Australia's electricity transmission and distribution networks, and build the case for potential economic savings that can be achieved through reducing load on these networks. In creating a tool to spatially visualise this analysis, it aims to provide a resource of value to decentralised energy proponents, governments and electricity network businesses looking for the most economic locations within the grid to apply decentralised energy technologies most cost-effectively, in order to maximise both consumer and environmental benefits. We invite feedback, suggestions, or other enquiries on all working papers. To comment on Intelligent Grid working papers, please email: louise.boronyak@uts.edu.au or refer to the Intelligent Grid website: www.igrid.net.au.

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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)
D-CODE	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	Megawatts -electrical
MWp	Megawatts -peak capacity
NEM	National Electricity Market
NSP	Network Service Provider
Opex	Operating expenditure
TNSP	Transmission Network Service Provider
TUOS	Transmission Use of System (charge)
WACC	Weighted Average Cost of Capital

Executive Summary

Introduction

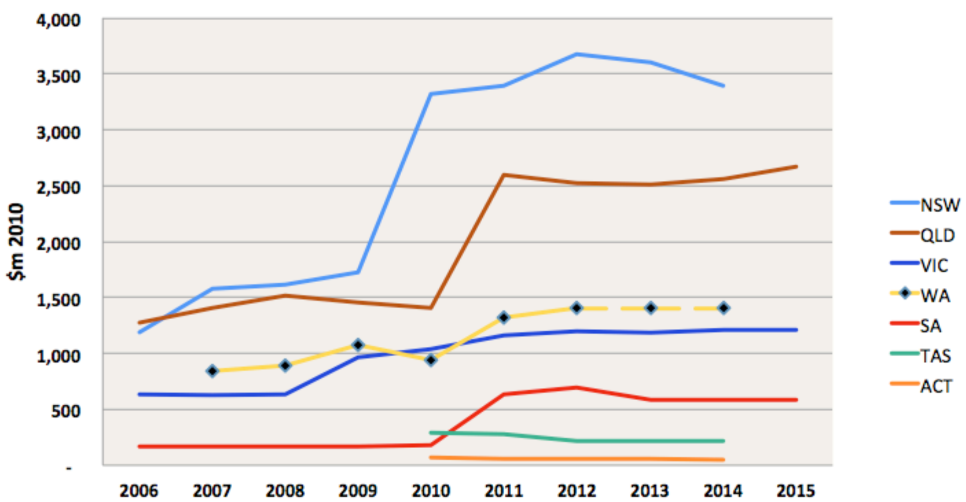
Electricity consumption is forecast to increase by almost 20 per cent in the next 10 years, while peak electricity demand is forecast to increase by 31 per cent over the same period (AEMO, 2010; WA IMO, 2010). An unprecedented level of electricity sector capital expenditure is planned over the current five-year period, a large component of which is to meet this growth in peak demand. Over $45 billion in electricity network infrastructure is planned from 2010-2015, which represents larger expenditure than the National Broadband Network in about half the time. This expenditure is resulting in dramatic increases in electricity prices around the country.

The business as usual approach to servicing peak demand growth through building bigger networks also reinforces the existing traditional model of large scale centralised and greenhouse gas intensive power supply. The central premise underpinning this Working Paper is that if implemented strategically, lower carbon 'Decentralised Energy' (DE) options have the ability to both reduce costs and reduce emissions, slowing or reversing the trends of rising peak demand, and rising consumer costs for delivering power from the producer to the end user. These Decentralised Energy options, also termed 'Demand Management' (DM) when used to address supply constraints, include 'distributed generation' sources embedded within the electricity network, management of peak loads and the implementation of end use energy efficiency.

Planned Network Investment

Figure 3 shows the regulator-approved network capital expenditure in each jurisdiction for the past two regulatory periods, 2006-2010 and 2011-2015. Note that the second regulatory period has seen a dramatic rise in investment, particularly in NSW and Queensland, which together account for over 60% of the total planned capital expenditure over the five years to 2015.

Figure 3**: Electricity Network Capital Expenditure by Jurisdiction, 2006-2015**

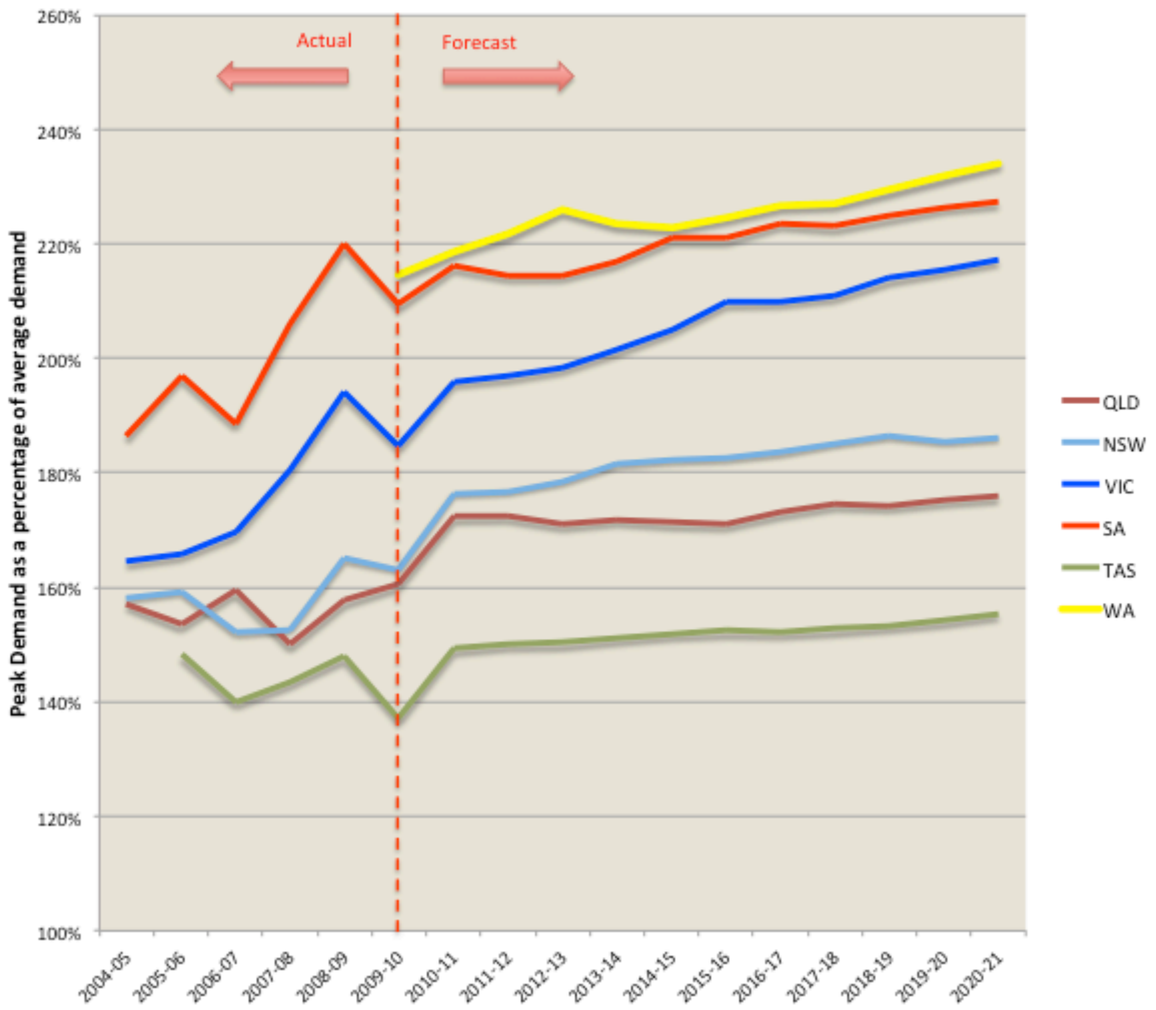


Investment Drivers

There are three primary drivers of this capital expenditure on network infrastructure: ageing infrastructure replacement; increased reliability standards imposed by governments on electricity utilities; and growth in peak electricity demand. The focus of this paper is on the final driver, peak demand growth. Over the next 10 years, overall peak demand is forecast to increase at a rate 0.7% per annum faster than total electricity consumption, totalling a 31% increase by 2020.

This forecast trend of peak demand outstripping energy demand, as shown in **Figure 7**, is most concerning from the perspective of electricity prices. With the forecast demand under business-as-usual conditions becoming peakier, this results in greater infrastructure intensity and ensuing higher costs for every unit of electricity delivered from centralised power stations to end users. This indicates that growth-related infrastructure spending is expected to continue strongly for the foreseeable future, placing further upward pressure on electricity prices.

Figure 7: Actual and Forecast Peak Demand as a Proportion of Average Demand by State, 2004-05 to 2020-21



What is 'Avoidable' Investment?

The central objective of this Working Paper in the context of Project 4 of the Intelligent Grid Research Program is to explore the opportunities to apply efficient 'non-network' alternatives to overcome network constraints, thereby saving consumer dollars and reducing emissions in the process. These opportunities are based on the principle of Decentralised Energy deferring or avoiding the building of *new infrastructure*. The distinction between 'deferral' and 'avoidance' of infrastructure investment is relatively simple: the difference is merely in the amount of time for which an investment is delayed. If there is an impending growth-driven network constraint that would require a $10 million network solution to overcome, 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 augmentation 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 beyond the relevant planning horizon.

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

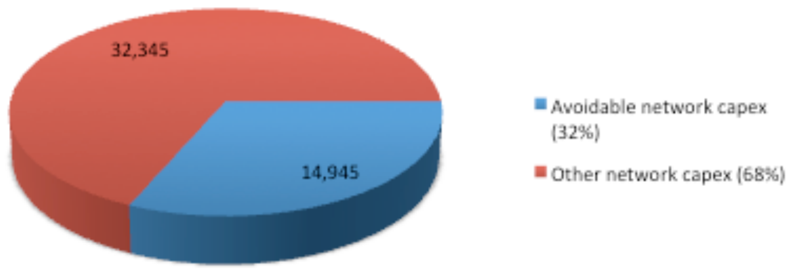
However, not all network capex is avoidable. In the context of the application of DE or 'non-network' options, avoidable capex costs are considered to be those costs that are 'growth related'. That is, investments that are undertaken in response to growing peak demand.

Extending network capacity, either to address demand growth or to meet new reliability criteria imposed by Governments are considered avoidable if demand on the network could be reduced. In practice, meeting new reliability criteria often implies very large changes in effective capacity, which if implemented quickly may be beyond the capacity of DE to address. Thus, in order to adopt conservative assumptions, the only network infrastructure costs that have been quantified and classified as 'avoidable' are 'network augmentations' specifically addressing peak demand growth.

Quantifying Avoidable Investment

The results of our analysis are shown in Figure 8 below, which indicates that there is a total of $14.9 billion of potentially avoidable capital expenditure if demand growth was to be eliminated. NSW accounts for just under half of this value, while Queensland is responsible for almost 20 per cent. Overall, almost one third of network capex in Australia is potentially avoidable over the current five-year regulatory period.

Figure 8**: Avoidable network costs relative to total network capex ($m 2010)**[1]



If even a portion of the $14.9 billion shown in Figure 8 above was redirected towards efficient DE options, substantial economic and greenhouse gas emission savings could be achieved relative to the business-as-usual approach. To determine the value below which DE 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 DE was able to defer the need to implement its identified network solution to a capacity constraint for one year. This can be used as a proxy for the maximum value that society should be willing to pay for the implementation of DE if the same reliability and service criteria are met.

The 'annual deferral value' factors in both the capital expenditure on network augmentation and the amount of growth being serviced by the proposed capacity addition, and considers the annual value to be around 10% of the investment value, after factoring in the Weighted Average Cost of Capital (WACC) and the avoided depreciation.

The DANCE Model

While there are huge opportunities for economic efficiencies to be gained through the deferral of network infrastructure, these opportunities are "obscured" within a complex electrical network and vary greatly in value according to both time and location. 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.*

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 annual reporting and other simple network planning data and creating simple but powerful interactive visual outputs, DANCE has the potential to provide a useful demand side engagement tool for network businesses. By making this information more accessible, **DE service**

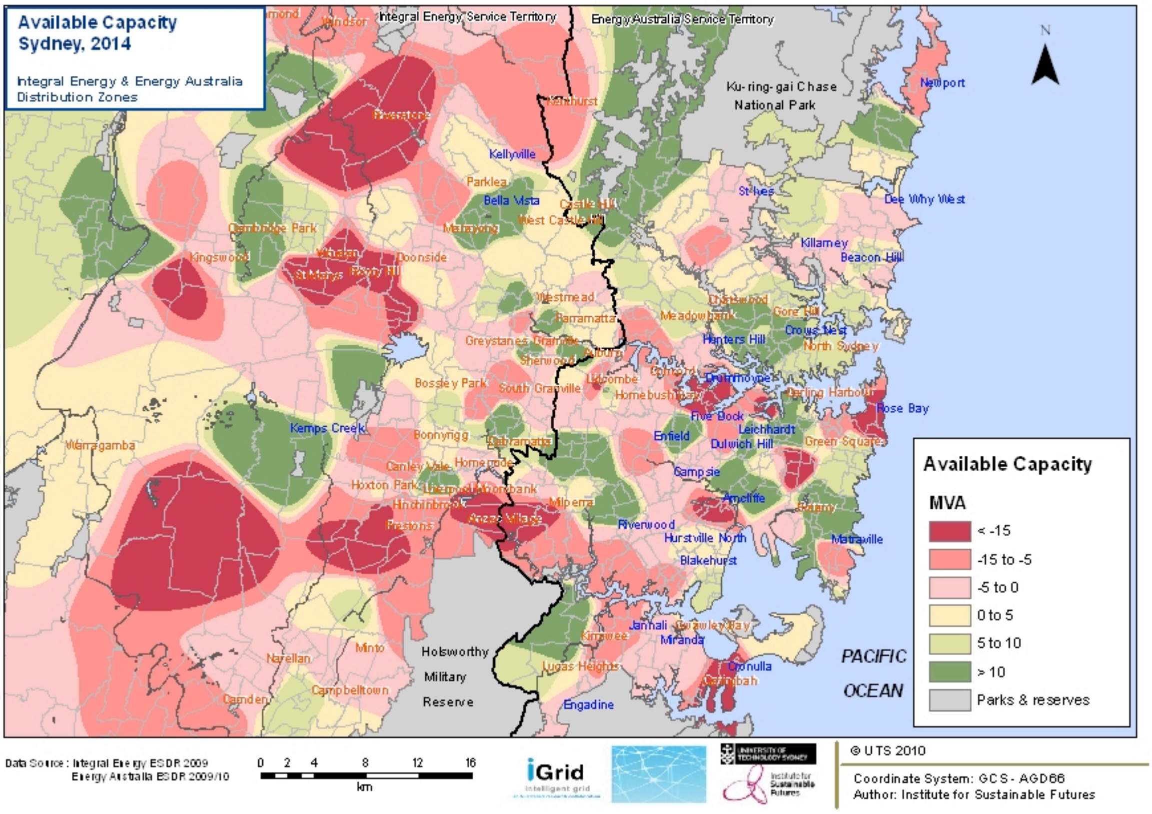
[1] In this paper we do not count network operating costs that would be directly avoided by eliminating the need to maintain new additional network infrastructure, which is in the order of a further 20 to 25 per cent of the annual deferral value (Langham et al. 2010).

providers can be assisted in locating the geographical areas and timeframes that they should be looking to develop projects in order to achieve the greatest benefit from their products and services. DANCE also helps to communicate to **policy makers** needing to understand the dynamics of where and how DE can contribute to beneficial economic and environmental outcomes. The GIS mapping outputs from DANCE are summarised below.

Available capacity

Figure 15 maps 'firm capacity' minus the forecast peak demand in 2014. The green and yellow colours indicate distribution zones that have sufficient spare capacity in 2014, while the pink and red colours indicate distribution zones facing growth-related constraints where investment will be needed to ensure reliability is maintained. The colour of the substation label indicates whether it is a winter (blue) or summer (orange) constraint.

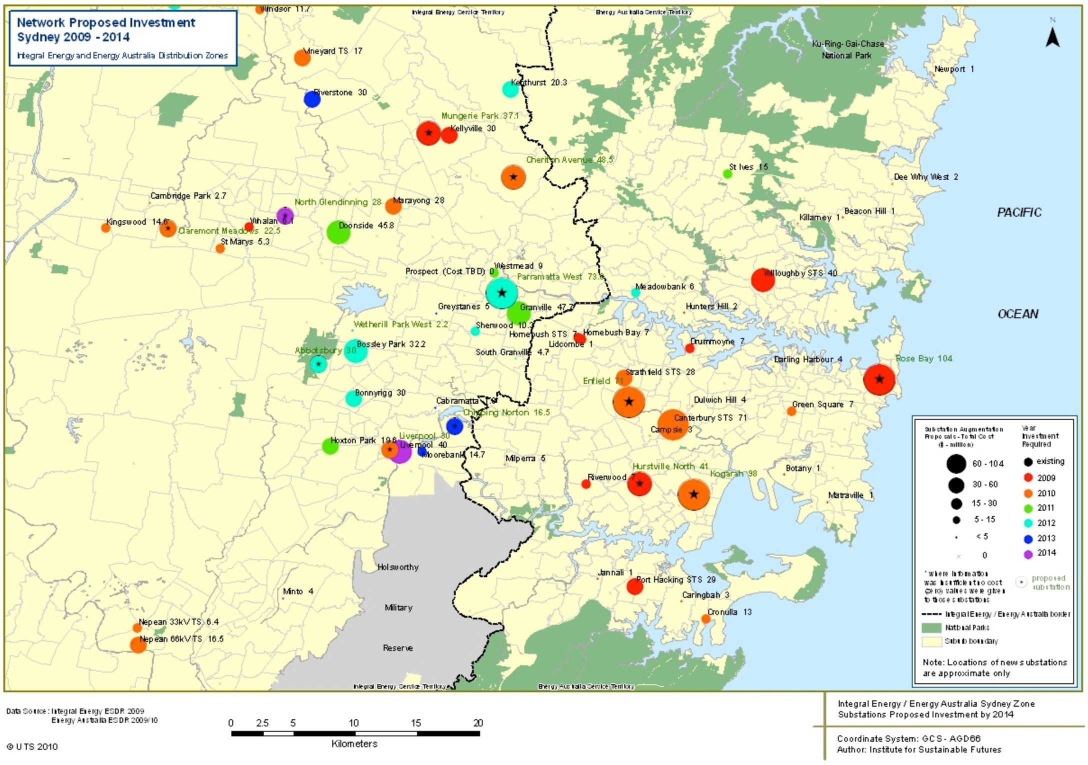
Figure 15**: Available Capacity (MVA)**



Total Investment

Figure 16 shows the total investment in network augmentations between 2009 and 2014, as reported in network annual planning documents. The size of the dots is indicative of the magnitude of investment, ranging from around $1-2 million up to $104 million for a new substation in Rose Bay on the south side of the opening to Sydney Harbour. The colour of the dots indicates the year of planned investment. This is the year in which DM would need to be delivering the demand reductions sufficient to overcome the constraint.

Figure 16**: Total Investment in Network Augmentation**

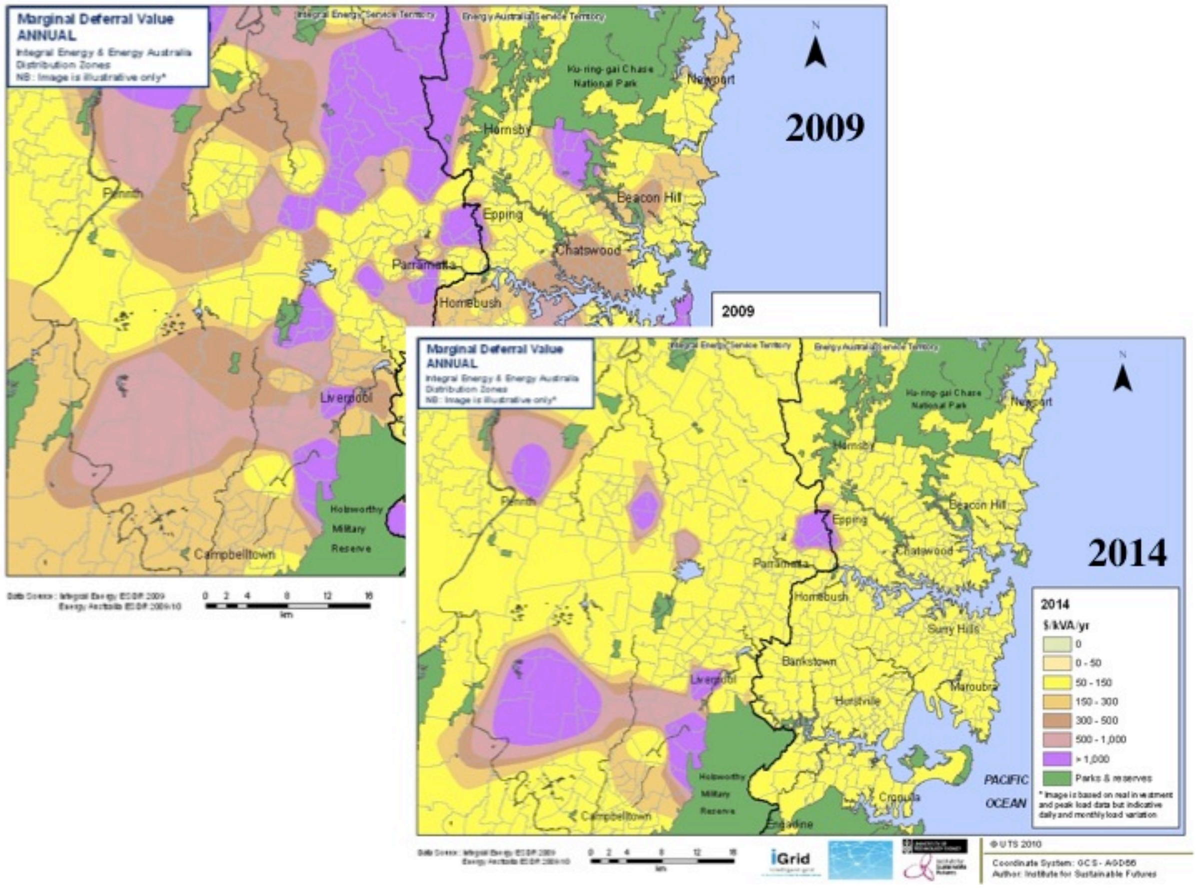


Marginal Deferral Value: Annual, Monthly and Hourly

Figure 17 shows the Annual Marginal Deferral Value map. Areas with neutral colours are those with limited to no deferral value, while marginal deferral value increasing strongly towards the brown and purple categories ($300-1000/kVA/yr).

Note in Figure 17 that in 2009 (left) there are many regions where cost-effective DM opportunities are available. By 2014 (right), 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 2014 image does not show, however, is that there would be new network investments appearing each year with every updated network planning report.

Figure 17**: Annual marginal deferral value for 2009 (left) and 2014 (right)**



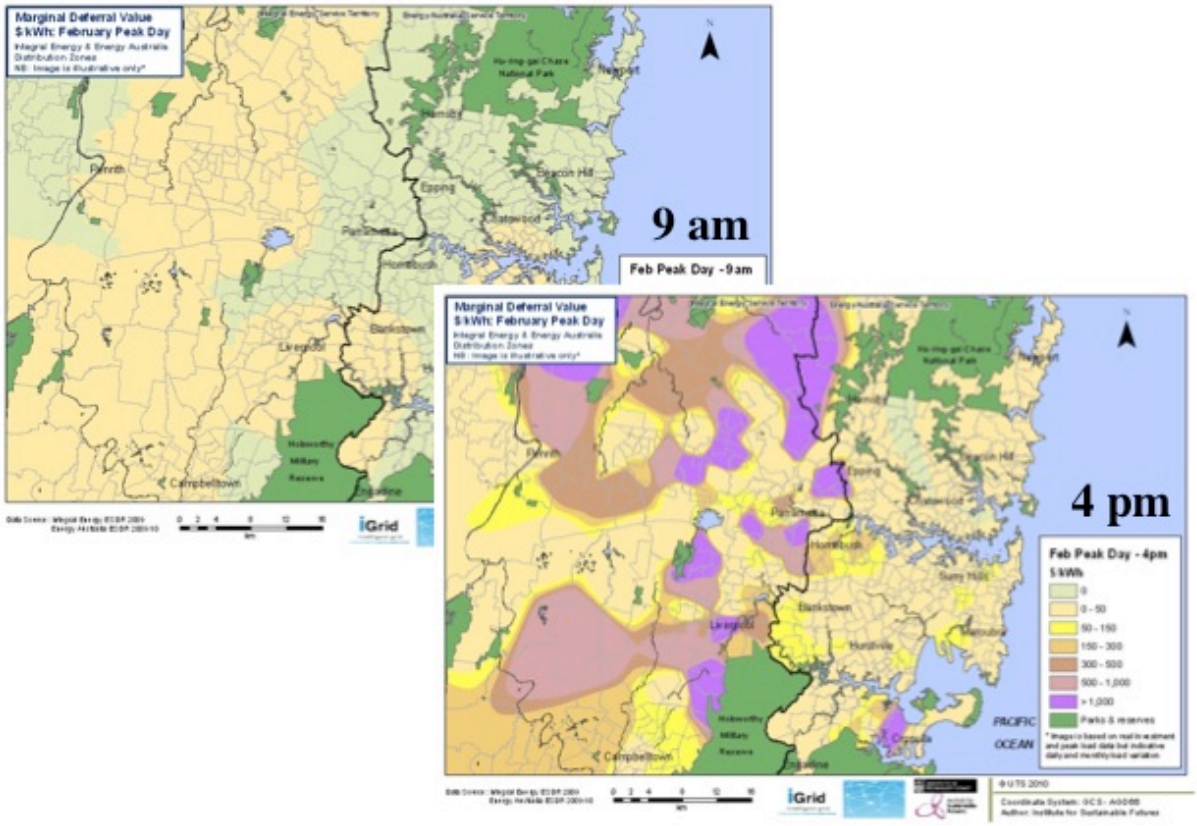
The DANCE Model goes further to break down the deferral value into the monthly time periods and hourly timeslots on key peak days in which those constraints are occurring. In doing so it offers insights into the types of electrical loads driving the constraints, and how brief are the constraint periods driving the billions of dollars of investment outlined in Section 3.2. Figure 19 shows two examples of the hourly deferral value maps, for 9am and 4pm respectively on the February peak day for 2009. Again, the category classes are the same as for the annual and monthly deferral value maps, only the units differ, this time in \$/kVA/hour, or \$/kWh[2] – the most common unit of energy billing. This analysis reveals that even in constrained zones with lower deferral value, we are seeing figures of \$300/kWh – 1,500 times the roughly \$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 limitations of current peak period time of use tariffs (typically about \$0.40/kWh) to reflect an adequate price signal to consumers to reduce demand.

It is practically and politically impossible for truly cost reflective pricing to be realised at the values shown in Figure 19. Providers of non-network solutions that alleviate a constraint by reducing peak

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

demand at a particular facility may obtain benefit to some degree if they are offsetting standard tariffs, 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.

Figure 19**: Hourly marginal deferral value for 9am (left) and 4pm (right) on the February peak day**[3]



Conclusion

There is very large potential for economic savings that can be tapped through Decentralised Energy in the context of Demand Management to avoid or defer electricity network constraints, with up to $14.9 billion of network capital investment in principal avoidable nationally over the current five year period. The DANCE Model provides a visual tool to assist stakeholders to understand “where” and “when” Decentralised Energy can be most effectively applied, to unlock the economic and environmental benefits of Decentralised Energy.

[3] The hourly and monthly mapping outputs of the DANCE Model provided in this paper utilise publicly available network planning data from the Sydney metropolitan region, in the network service territories of Energy Australia and Integral Energy. Although all investment and demand growth figures are real, details that were not publicly available, such as load curves for specific substations, have been assigned illustrative values. Therefore the hourly and monthly time step images shown in this paper are intended merely to demonstrate the mapping potential of the tool applied more so than the results that are shown.

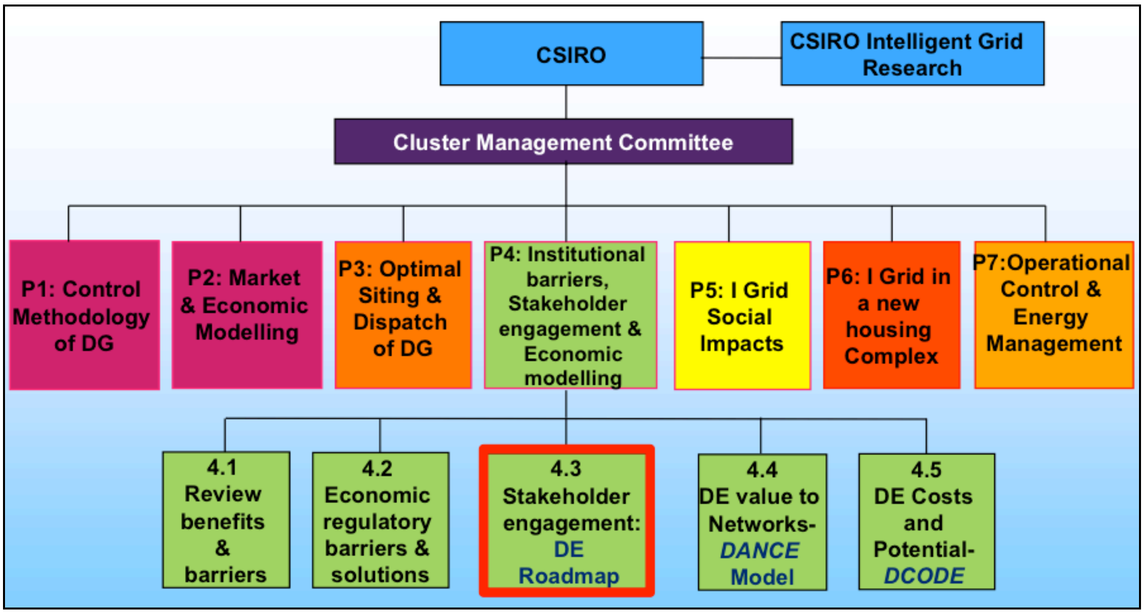
1. Introduction

1.1 The Intelligent Grid Research Program

The Intelligent Grid (iGrid) Research Program is a three-year research collaboration between the CSIRO and five leading Australian universities under the CSIRO Energy Transformed Flagship. Its aim is *to facilitate major greenhouse gas emission reductions by integrating Decentralised Energy technology with a more intelligent electricity network.* The iGrid program is an interdisciplinary venture that complements other research being undertaken through the CSIRO Energy Transformed Flagship. It brings together economists, engineers, social scientists, systems scientists and policy scientists to develop integrated insights that could not be achieved if members of these disciplines worked independently of each other.

Figure 1 below illustrates the structure of the iGrid Research Program and shows how Project 4, which focuses on institutional barriers, stakeholder engagement and economic modelling, fits into the wider program context. This working paper, shown as "DANCE Model" below, details the economic modelling of avoidable network costs of electricity that can potentially be delivered through the use of "Decentralised Energy" (see Section 1.2 below). For more details about the iGrid Research Program please refer to the iGrid website www.igrid.net.au.

Figure 1: Intelligent Grid Research Program structure



In other words, the working papers could be said to outline the "what, where, how, how much who and why" surrounding the development of Decentralised Energy:

- **WHY: 4.1 Barriers and benefits of Intelligent Grid** – outlines *why* the Intelligent Grid and Distributed Energy more specifically should be pursued, *why* the market is not operating efficiently and *why* specific intervention is required if large-scale uptake is to be realised.
- **HOW / WHO:**
    - **4.2 Policy Tools for Distributed Energy** – provides an overview of *how* the large-scale uptake of Distributed Energy could be successfully achieved through appropriate policy means, and *who* carries responsibility to undertake such efforts.
    - **4.5 Business Deliberation & Australian DE Roadmap** – this work brings all relevant stakeholders together to establish a vision for Distributed Energy within the Intelligent Grid and intends to build momentum and consensus around means of realising this vision.
- **WHAT / HOW MUCH: 4.3 DCODE Model** – this model and associated paper provide a tool to assist interested stakeholders in understanding what types of Decentralised Energy make economic sense to apply in their area of interest.
- **WHERE / WHEN: 4.4 DANCE Model** – the DANCE model and associated mapping outputs provide a means for network businesses, policy makers and Decentralised Energy proponents to understand when and where their technologies can be applied most cost-effectively within the electricity network.

1.2 Decentralised Energy and the Intelligent Grid

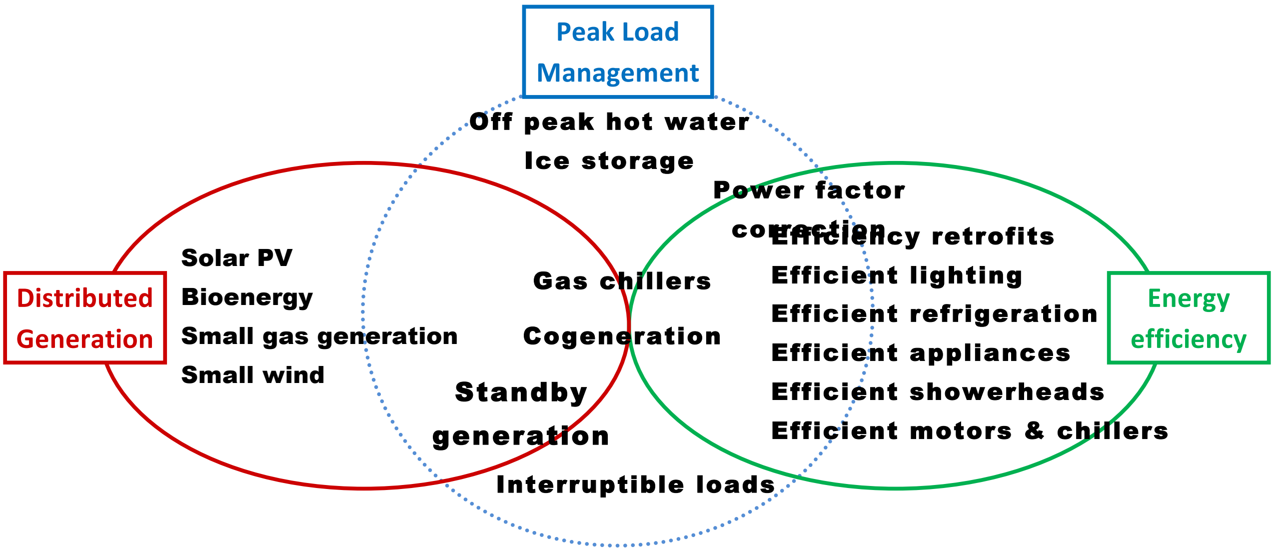
The terms 'Intelligent Grid' and 'Smart Grid' have become increasingly used over the past few years and care needs to be taken to clearly define them. For the purposes of this research program, an 'Intelligent Grid' is an electricity network that uses 'Decentralised Energy' resources and advanced communication 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, the term 'Decentralised Energy' ('DE') means electricity generation and management of energy use applied at the consumer or distribution network level. It includes 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 end users utilizing equipment or implementing behaviours that can achieve the same outcome with less energy input.

These DE 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 to defer or avoid the need to investing additional centralised electricity supply infrastructure this can be termed 'Demand Management'. Therefore the terms Demand Management (DM) and Decentralised Energy (DE) are used interchangeably for the purposes of this report (given its primary focus is on overcoming network constraints).

Figure 2: Some Decentralised Energy resources (adapted from IPART 2002, p. 102)



1.3 Why Network Costs Matter

Electricity consumption is forecast to increase by over 20 per cent in the next 10 years (AEMO, 2010) while summer peak electricity demand is forecast to increase by over 30 per cent over the same period. An unprecedented level of electricity sector capital expenditure is planned over the current five year regulatory period, a large component of which is to meet this growth in total and peak demand. Over $45 billion in electricity network infrastructure alone is planned from 2010-2015, which represents larger expenditure than the National Broadband Network in less than 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. In the case of Sydney, the five years to 2014 will see electricity prices rise by an average of over 80 per cent, with the share of power bills that goes to pay network charges rising from 40 per cent to almost 60 per cent (Dunstan and Langham, 2010).

The business-as-usual approach to servicing peak demand growth through building bigger networks reinforces the traditional model of large scale centralised and greenhouse gas intensive power supply. However, when the urgency of reducing national greenhouse gas emissions in the face of Australia's growing demand for energy is considered alongside the need to stem steep price increases for consumers, there are strong incentives to consider alternatives. If implemented strategically, low carbon Decentralised Energy options have the ability to meet the parallel aims of reducing costs and reducing emissions, by slowing or reversing the trends of rising peak demand, and rising consumer costs for delivering power from the producer to the end user.

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. That is, by reducing peak electricity demand through energy efficiency or load management (the orange, green and blue circles in Figure 2 above), or by generating power close to the consumer using 'distributed generation' (the red circle in Figure 2), this can avoid the need for capital intensive transmission and distribution infrastructure upgrades to supply more peak power to that network area from centralised generators long distances from consumers. This is the central premise underpinning this Working Paper.

1.4 Rationale for the DANCE Model

The existing regulatory framework for the electricity sector recognises the efficiencies that can be gained from Demand Management (DM) or 'non-network solutions', in that each time a growth-related network 'augmentation' of sufficient size[4] is proposed, the network operator is required to assess the relative merits of non-network alternatives in meeting the constraint.[5] Yet despite relatively low penetration of demand management in the National Electricity Market (NEM) and reviews suggesting substantial untapped potential for cost-effective DM (IPART 2002), the large majority of investigations into DM result in the conclusion that there are insufficient efficient demand management options available to overcome a constraint.[6]

While there is little primary research on the specific reasons for Australia's low DM conversion rate, Working Paper 4.1 on Barriers to Intelligent Grid (Dunstan et al 2011) suggests that there are several factors missing from the DM project development equation:

- A lack of accessible information for DM participants on the timing and location of network constraints that are required to be addressed, if DM it is to be applied most cost-effectively.
    - Once this information is available, then a mechanism for DM providers to capture a portion of the avoided network costs to unlock greater cost-effective DM potential.
- Insufficient lead times to develop adequate levels of DM.
- Lack of skills, experience and precedents within electricity networks (and DM providers) to deal with the application of non-network solutions.
- Cultural barriers within utilities favouring business-as-usual network infrastructure options.

These institutional barriers restrain the market for DE, slowing its development, thereby creating a feedback loop restricting its potential application at large scale for demand management.

[4] The trigger value for the mandatory consideration of non-network options is currently $5 million for transmission investments and is proposed to be $5 million for distribution.
[5] Under sub-clauses within National Electricity Rules (NER) 5.6.5.
[6] As an example, only 5 of 68 of Ausgrid DM Screening Tests had as of November 2011 resulted in DM implementation, another 8 were pending further investigation. See: http://www.ausgrid.com.au/Common/Our-network/Demand-Management/Program-progress-tracking.aspx

The Dynamic Avoidable Network Cost Evaluation Model (DANCE Model) was created to assist in overcoming the first of these barriers listed above, by providing an information tool that network businesses and DM providers alike can utilise to better understand the potential of non-network options. This is in recognition of the fact that the time and place where DM is needed to unlock this value stream varies dramatically by season, time of day and – critically – location on the network.

The DANCE Model is an economic analysis and mapping tool that uses electricity network planning investment and electricity demand data to calculate and geographically map the value that could be unlocked by non-network options in avoiding network augmentation caused by demand growth.

The DANCE Model comprises three parts: the Excel model, the GIS mapping layers, and the actual specific maps produced using the GIS. It is intended that the Excel model and GIS layers be made available to network businesses partnering with the iGrid team to apply DANCE in their network territories, while the visual outputs will be made publicly available to allow the networks, DE service providers, planners and interested stakeholders to engage with the possibilities for DE implementation.

1.5 Aim and Scope of this Working Paper

This working paper aims to:

1. Examine the current and proposed costs associated with developing Australia's electricity transmission and distribution networks between 2010 and 2015;
2. Outline the case for and magnitude of economic savings that could be achieved by reducing congestion on electricity networks;
3. Explain and showcase the DANCE Model, which uses economic analysis of network spending and constraint data to "map the value hot spots" to visualise the time and geographic location where applying DE could yield the greatest economic benefit.

The example mapping outputs of the DANCE Model provided in this paper use publicly available network planning data from the Sydney metropolitan region, in the network service territories of Energy Australia and Integral Energy. Although all investment and demand growth figures are real, details that were not publicly available, such as load curves for specific substations, have been assigned illustrative values. Therefore the hourly and monthly time step images shown in this paper are intended merely to illustrate the mapping potential of the tool rather than to provide definitive value estimates.

To gain a fuller appreciation of the relative costs and benefits of DE compared to centralised power supply, this Working Paper should be read in combination with Working Paper 4.3, which outlines the details and costs of different DE options.

It is hoped that the DANCE Model may eventually be applied to all network jurisdictions in Australia to gain a national picture of DE opportunities. Network businesses that would like to know more about partnering in this process are invited to contact the authors through the Institute for Sustainable Futures at UTS.

2 Electricity network investment in Australia

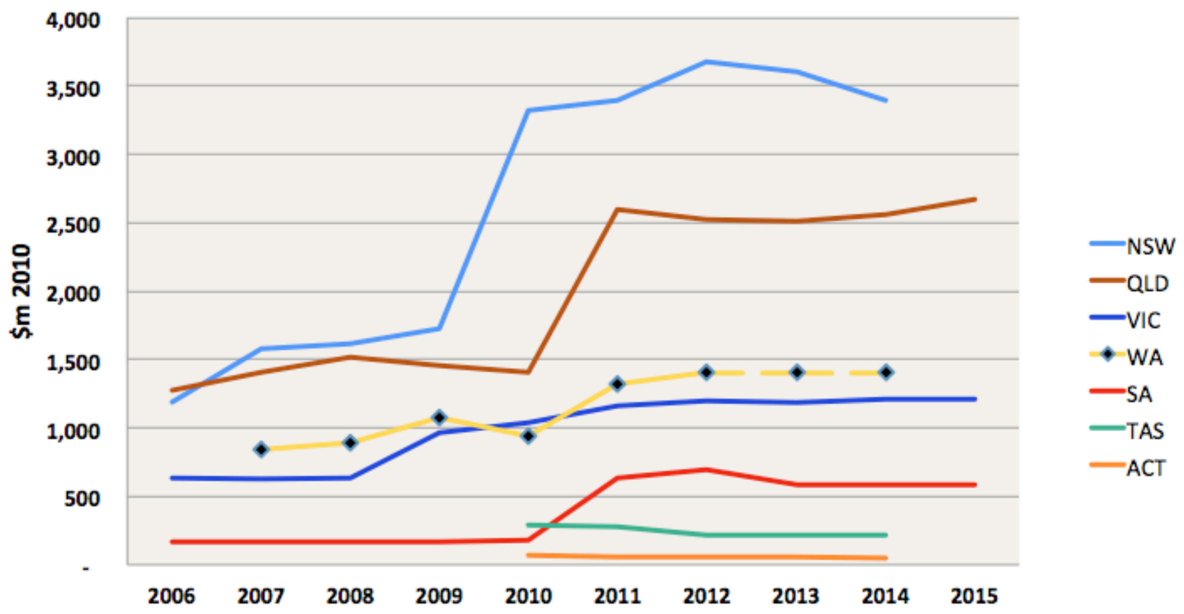
2.1 Planned network investment

Australia's electricity network is currently undergoing a dramatic increase in capital investment relative to previous decades. The most recent analysis of final regulatory determinations for all jurisdictions reveals that in most recent five year regulatory periods (to 2014/15) or extrapolated, capital expenditure in electricity transmission and distribution networks is expected to total more than $47 billion[7] across the nation, or more than $9 billion per year. Despite the magnitude of this investment and the implications for consumer electricity prices, this investment has until recently received little public attention, perhaps 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. To date, utilities have generally taken a traditional approach that favours network solutions. The AER then determines for each network how much of that estimate it considers to be an "efficient" level of spending; generally reducing proposed expenditure by some margin. These costs are then recovered by the network through electricity tariffs over the life of the assets, typically a period of approximately 40 years.

Figure 3 below shows the regulator-approved network capital expenditure in each jurisdiction for the past two regulatory periods, 2006-2010 and 2011-2015.[8] Note that the second regulatory period has seen a dramatic rise in investment, particularly in NSW and Queensland. Figure 3 does not show that this escalation was on top of earlier spending increases of approximately over 180 per cent on the period 2001-2005 in the case of NSW and Queensland (Simshauser *et al.* 2010).

[7] In $2010 AUD.
[8] Each jurisdiction runs on a slightly different regulatory cycle.

Figure 3: 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, excluding NT (insufficient data). For Western Australia the final two years are a simple extrapolation of the last available year's approved planned transmission and distribution network investment (also represented by the dotted line in Figure 17, while Tasmania's approved planned distribution network investment was also extrapolated by two years (transmission is as approved to 2014). NSW and Queensland together account for over 60 per cent of the total capex.

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

** 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, 2009b, NSW Final *distribution determination 2009-10 to 2013-14 (Final decision, 28 April 2009),Tables 7.16, 7.17 & 7.18; AER, 2009d, Transgrid Draft Transmission determination 2009–10 to 2013–14, Table 2. (31 October, 2008).*

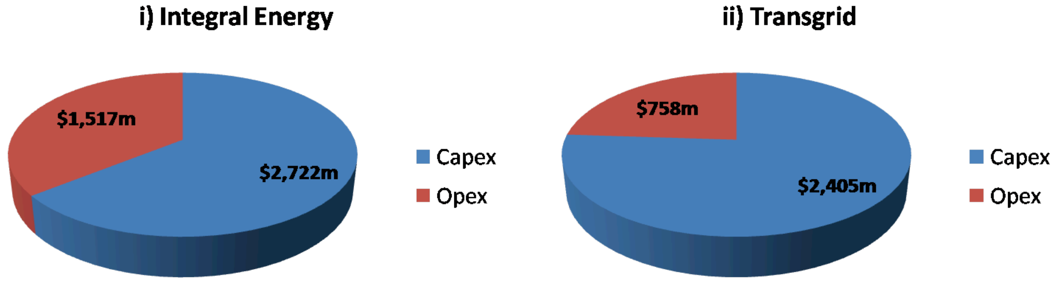
2. AER, 2010a, QLD distribution determination 2010-11 to 2014-5 (Final decision, May 2010), Tables 7.21 & 7.22; AER, 2007, Decision— Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12 (14 June 2007), Table 3.4.
3. AER, 2010c, Victorian electricity distribution network service providers distribution determination 2011–2015 (Final decision, October 2010), Tables 5.25-5.27; AER, 2008b, SP AusNet transmission determination 2008-09 to 2013-14 (Final Decision, January 2008), Table 4.27.
4. AER, 2010b, South Australia distribution determination 2010-11 to 2014-5 (Final decision), May 2010, Table 7.8; AER, 2008a, 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, 2007, 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, 2009c, Transend Transmission Determination 2009–10 to 2013–14, 28 April 2009, Transend, Table 4.12.
6. AER, 2009a, ACT Final Determination 2009-10-2013-14, Table 8.11. To avoid double counting TransGrid expenditure was not included in the above table for ACT.
7. Economic Regulation Authority, 2010, Further Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network, 19 January 2010, Table 3.

2.2 Network capital investment in context

The above discussion has centred on network capital investment (capex). Network capex includes investments which expand network capacity to meet increasing peak-demand, plus those which create new customer connections, provide fixed operating capital such as information technology and service vehicles, and replace ageing infrastructure. To place the discussion of network capex in context, it is useful to briefly outline the magnitude of the other primary areas of electricity sector investment: generation capital and operating investment, and operating expenditures (opex) of electricity networks.

Within electricity network infrastructure, capex is the dominant component. However, there are also significant expenditures on the operation and maintenance of network infrastructure. The actual breakdown of capital versus operating expenditures on electricity networks varies according to whether it is a transmission or distribution network, the stage in the infrastructure replacement cycle, and the nature of the service territory in terms of rural or urban settings. Nonetheless, Figure 4 provides example breakdowns of a distribution (Integral Energy, now Endeavour Energy) and a transmission network (Transgrid) in the most recent regulatory period. In both cases capex is strongly dominant. Opex is of less interest, as it is a function of the network assets that are installed and can largely only be avoided through limiting further infrastructure building. Further discussion of the “avoidable” nature of this investment follows in Section 3.

Figure 4: Example Capex & Opex Breakdown for NSW Electricity Transmission and Distribution Networks over the current regulatory period



Source: Langham et al. (2010).

Electricity generation infrastructure and fuel make up the other major component of electricity bills. While the exact type of new generation sources is not yet clear and is subject to market forces, recent analysis of planned overall infrastructure spending indicated that capital investment in new generation to 2020 plus the maintenance of both these generation assets as well as network assets (the red wedge in Figure 4 above) equate to roughly an additional 80 per cent of the network capex value (Langham *et al.* 2010). Thus network capital is still the largest cost facing the industry over the next 10 years. Although fuel costs are not considered "infrastructure", the same study indicated that fuel costs account for a further 40 per cent of the total infrastructure costs discussed above.

While costs associated with centralised generation do represent a significant portion of potential avoided costs from the application of DM, they are less spatially variable (less specific to a particular location on the network). As the DANCE Model is about mapping spatial variation, it is restricted to network costs and does not consider generation. Additionally, comparative generation costs are generally part of the project development equation when assessing the cost-effectiveness of distributed generation sources, for example, while the marginal costs associated with meeting new network demand are generally *not* part of this equation. Highlighting this significant but commonly unvalued avenue for efficiency gains is central to this working paper.

2.3 Drivers of electricity 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 working lives;
- Increased reliability standards imposed by governments on electricity utilities; and
- Strong growth in peak demand.

To a lesser extent network expansion due to new customer connections is another significant component of capital expenditure, however this factor is anticipated to have remained relatively consistent over the years in parallel with population and economic growth rates.

Ageing infrastructure replacement

As much of Australia's electricity network infrastructure was built in the 1970s and networks have working lives of around 40 years, much of the existing network is nearing its replacement age. Thus we are seeing levels of network investment for infrastructure replacement not dissimilar to that experienced during the initial period of network development. The business-as-usual approach to infrastructure replacement is to rebuild the same or larger capacity infrastructure to account for anticipated levels of electricity demand growth. Thus there is often *both* a "replacement" component and a "growth" component to this capital investment (capex). The relative proportion of capex addressing the growth component in these cases is somewhat smaller than it would otherwise be if other necessary replacement works were not otherwise underway.

Increased reliability standards

As part of network license conditions, government impose reliability and security of supply standards that electricity networks must meet. While the cost of achieving such small incremental improvements in an *unreliable* electricity system is relatively small, raising reliability criteria by even a small margin in a reliable electricity system such as in most of Australia is quite expensive. For example, the NSW Government has committed to raising reliability standards by 0.01%, or 53 minutes less average outage time per year (Dunstan and Langham, 2010). This commitment has required Energy Australia to raise reliability criteria in the Sydney CBD from 'n-1' to 'n-2' by 2014, meaning that power must remain on even if the largest two power supply lines or transformers to the CBD fail at the same time (as opposed to one for n-1). This change has significant implications for required investment and associated energy prices.

Peak demand growth

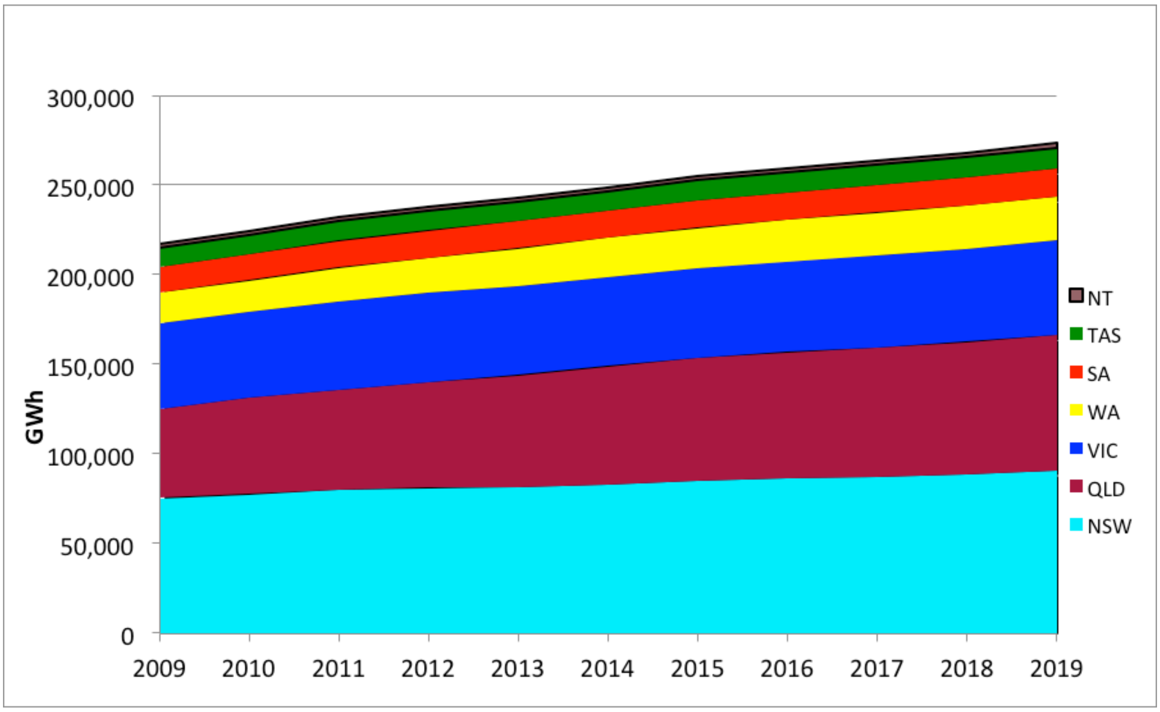
Peak demand refers to the single highest instantaneous use of electricity during the course of a year. It generally occurs on particularly hot or cold weather days, when consumers have high usage of electricity for space heating and cooling in buildings. In recent years Australia has seen strong growth in the uptake of air conditioning in different building sectors, which has led to the faster growth of summer peak demand than winter peak demand in most jurisdictions. As distribution networks are large and diverse with different capacities to transfer electricity at each point on the grid, the timing and size of the peaks differs for every area. Some areas have winter peaks, while others have summer peaks.

To avoid power outages, the generation and distribution systems must have sufficient power supply capacity 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. To explain this further it is necessary to look at trends in total energy consumption and in peak demand before observing how the two relate.

Total electricity consumption across Australia is forecast to increase steadily at a rate of 2.4% per year over the next decade (AEMO 2010), amounting to a total increase of 24% by 2020 (Figure 5). With the electricity making up 37 per cent of Australia's total greenhouse gas emissions (DCCEE 2010), this trend contrasts sharply with Australia's international commitments to reduce its greenhouse gas emissions by 5 to 25 per cent by 2020.[9]

Figure 5: Forecast National Electricity Consumption, 2010-2020

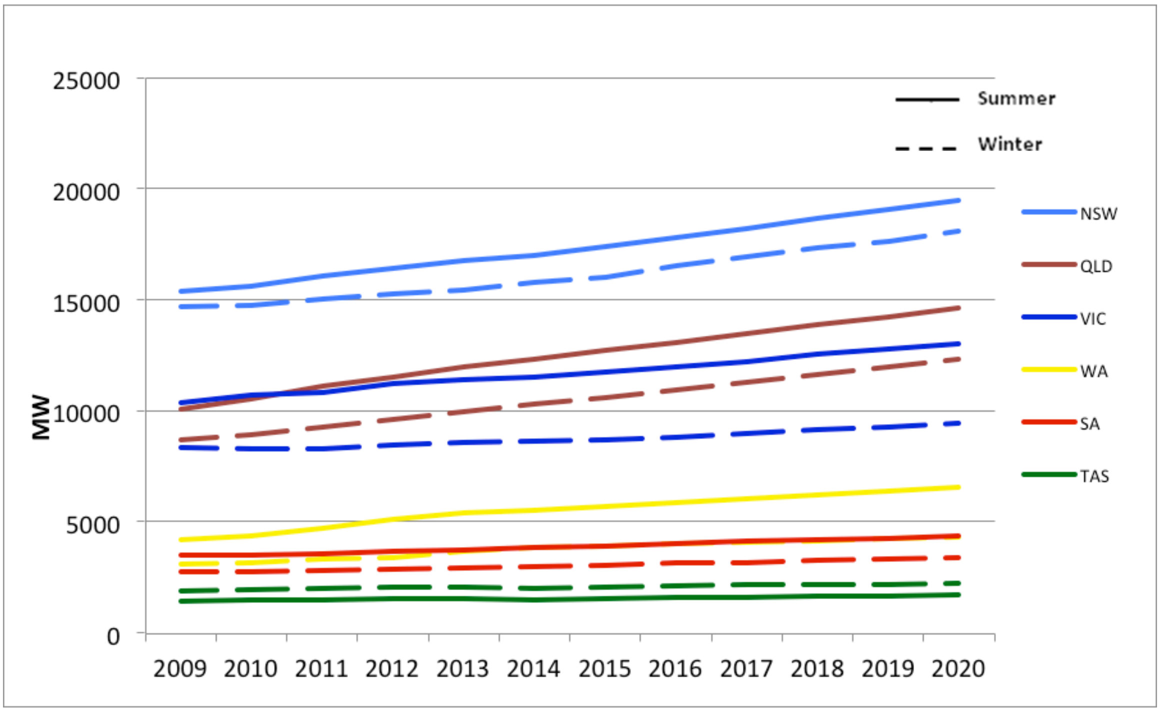


Data sources: AEMO 2010 Electricity Statement of Opportunities Medium Growth Scenario (NSW,QLD,VIC,SA,TAS), Power and Water, 2009, Company Statement of Corporate Intent 2009-2010 (NT) with simple extrapolation from 2010-2020, and WA IMO Statement of Opportunities 2010 (WA).

Over the same period, overall peak demand is forecast to increase at a rate 0.7% per annum faster than total electricity consumption, totalling a 31% increase by 2020 (AEMO 2010; WA IMO, 2010), as shown in Figure 6 below. The solid lines in Figure 6 represent summer peak forecasts, while the dotted lines show the winter peak, and colours are consistent for each jurisdiction. Note that all states except for Tasmania have a dominant summer peak.

[9] Note: commitment higher than 5 per cent is conditional upon coordinated international action.

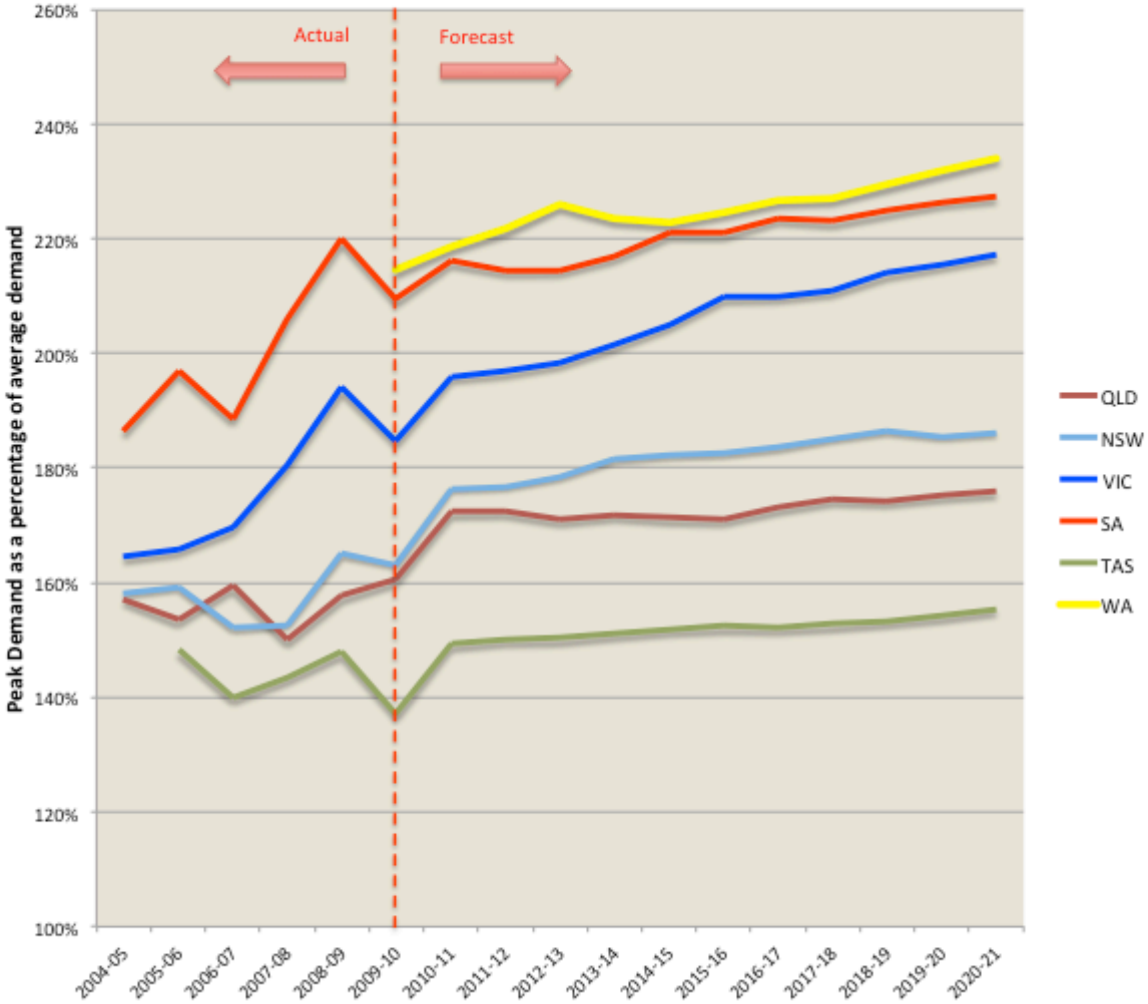
Figure 6: Electricity Peak Demand Forecast to 2020 by Jurisdiction



Sources: 2010 AEMO Electricity Statement of Opportunities (NSW,QLD,VIC,SA,TAS) and WA Independent Market Operator 2010 (WA - SWIS only), NT not included due to data availability. All based on 10% Probability of Exceedance.

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 per kilowatt hour delivered. The key illustration of the forecast trend in the relationship between peak and total demand in Australia is shown in Figure 7. In 2009, peak demand is 1.82 times total electricity (average) demand. In just 10 years this is forecast to increase to 1.95 times. This indicates that the current observed trend of increasing investment in growth-related infrastructure is expected to continue strongly for the foreseeable future, placing strong upward pressure on electricity prices.

Figure 7: 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 Statement of Opportunities. Analysis excludes NT and is based on peak demand at 10% Probability of Exceedance (POE).

3 Avoidable network investment

3.1 'Avoidable' electricity costs and the role of decentralised energy

As outlined earlier, the electricity market typically responds to growth in peak demand by increasing generation capacity and by investing in transmission and distribution capital to increase the carrying capacity of the network. However, if utilised in the context of demand management (DM) to defer or avoid the building of *new infrastructure,* then Decentralised Energy (DE) has the potential to provide cost-effective alternatives by reducing demand, or increasing generation close to the source of demand.

This section outlines the specific components of network investment that are defined to be 'avoidable' or 'deferrable' for the purposes of the DANCE Model.

Avoiding or deferring network investment?

The distinction between 'deferral' and 'avoidance' of infrastructure investment is essentially the amount of time for which an investment is delayed. If there is an impending growth-driven network constraint that would require, say, a $10 million network solution to overcome, 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, then the need for augmentation of the network may be avoided altogether. This situation is what would be termed 'avoidance', but is in practice no different to the prolonged deferral of network infrastructure beyond the relevant planning horizon.

The vision of the Intelligent Grid is for DM to be implemented effectively and at scale into the future, slowing and stabilising total and peak growth in electricity consumption. 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* represents the maximum opportunity cost associated with forgoing opportunities to implement DE measures.

Defining Avoidable Network Costs

Not all network capex is avoidable. In the context of the application of DE or 'non-network' options, avoidable capex costs are considered to be those costs that are 'growth related'. That is, investments that are undertaken in response to growing peak demand.

The $47 billion of network capex includes investments associated with:

1. expanding network capacity to:
    a. meet increasing peak-demand, or
    b. comply with more stringent reliability standards;
2. extending the network to connect new customers to the grid;

3. replacing ageing infrastructure;
4. addressing two or more of the above drivers simultaneously; and
5. 'non-system' capital expenses, such as IT and service vehicles.

Non-system capital expenses (5) and the connection of new customers (2) are not considered to be avoidable in the context of grid-based DE. The replacement of ageing infrastructure (3) is not classed as avoidable in this analysis. However, in many cases there is also a growth related component (as in 4), or the replacement infrastructure would be less expensive if it was required to service a lower capacity. Furthermore, reducing demand on network infrastructure may extend the life of assets and therefore defer the need for replacement. Nonetheless, the difficulty of quantifying such benefits means that for the purposes of the DANCE Model and quantifying the magnitude of avoidable network costs nationally, this capex category has *not* been considered. Extending network capacity, either to address demand growth (1a) or to meet new security of supply criteria imposed by Government (1b) are considered avoidable if demand on the network could be reduced. In practicality, meeting new reliability criteria (1b) may involve large changes in effective firm capacity, which if introduced quickly may be beyond the capacity of DM to address. Further, in terms of classification of expenditure by network businesses, investment relating to reliability and security is commonly considered separately from 'growth-related' investments, which also known as 'network augmentations'. It is generally not clear to what extent DE could play a role in this, as it depends strongly on how the transition to higher reliability standards is enforced by Governments. This is an area that warrants further research.

Given the above, the only network infrastructure costs that have been quantified and classified as 'avoidable' in this analysis are those in the category of "Growth Augmentation" (category 1a). Therefore the figures tabulated for avoidable network costs below are likely to be relatively conservative.

This suggestion is reinforced when considering that in this paper we do not count network opex that would be directly avoided by eliminating the need to maintain new additional network infrastructure. This is in the order of a further 20 to 25 per cent of the annual deferral value (Langham *et al.* 2010).

3.2 Quantifying Australia's avoidable network costs of electricity

As explained in the previous section, for the purposes of the DANCE model and this paper, we have chosen to include only growth-related capex within the definition of 'avoidable network costs'. To determine the magnitude of these costs, a detailed review and analysis of transmission and distribution network business regulatory documents was undertaken across all jurisdictions for which information was publicly available.[10] The primary pieces of information gathered were:

- Forecast total capex over the regulatory period (presented above in Section 3.1)

[10] All jurisdictions except for the Northern Territory were assessed.

- The subset of forecast capex for "augmentations" (corresponds to 1a. above), or "growth related" if augmentations was not presented[11] (corresponds to 1a. + 2. above)

Table 2 below summarises the included and excluded avoidable cost components, and the terminology used in regulatory documents to refer to this expenditure classification.

Table 2: Summary of included and excluded "avoidable" capex

Capex component	Term used to report to AER	Potentially avoidable?	Included as avoidable in this study
Augmenting network capacity to address peak demand growth	Growth-related Augmentations	Yes	Yes
New customer connections	Growth-related Customer Connections	No	No[#]
Ageing infrastructure replacement	Replacement	Possibly deferrable in some cases	No
Investment to meet stronger reliability standards	Reliability, Service Enhancement, Compliance Obligations or similar	Yes (providing transition managed)	No

Notes: # Unable to be separated for NSW in this research

The results of this analysis are shown in Table 3 below, which indicate that there is a total of around $14.9 billion of potentially avoidable capital expenditure if demand growth was to be eliminated. NSW carries just under half of this value, while Queensland is responsible for almost 20 per cent. Note, however, that it was not possible to separate customer connections from augmentation capex due to NSW networks only reporting a combined "growth-related" figure. The amount of spending on customer connections relative to capacity augmentations (the two components making up the "growth-related" category) is highly variable depending on the jurisdiction and rates of population and economic growth, and thus it was not attempted to estimate this figure. This means that NSW figures represent a somewhat less conservative picture of avoidable investment than for other states, although in the absence of further information this was considered acceptable, particularly in light of the very large potentially avoidable capex components being experienced in NSW which fall outside the "growth related" category, such as that relating to increased reliability standards. Overall national total figures for augmentation and avoidable cost remain conservative as per the discussion in Section 3.1 above.

[11] Not all jurisdictions present this information in a consistent manner.

It should also be noted that this estimate of potentially avoidable capital expenditure, is based on a forward looking program of investment prior to the beginning of the current regulatory period. As these regulatory periods for each state are now partially expired, and much of this investment has now been completed or committed, this capex is no longer avoidable in practice. On the other hand, network investment will not abruptly cease at the end of the current regulatory period and therefore potential to avoid capex through DM extend well beyond the current 5-year period. So the estimate of potentially avoidable capex remains valid. Indeed, as DM has the potential to defer investment beyond the current regulatory period, it can be argued that the above estimate significantly understates the true potential value of Decentralised Energy options.

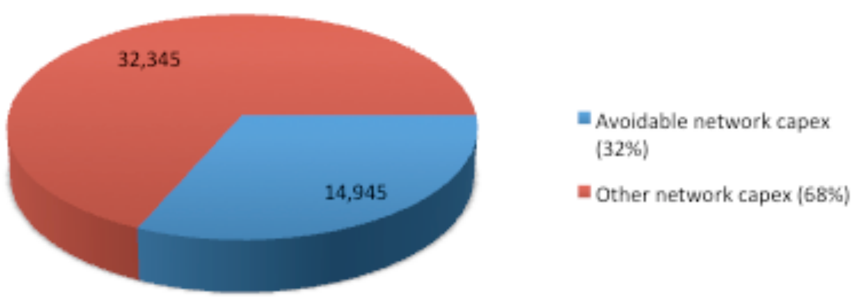
Table 3: Planned five-year augmentation capex by jurisdiction

	Augmentation expenditure ($m 2010)
NSW/ACT	7,295[#]
QLD	2,905
VIC	1,526
SA	1,426
TAS	508
WA	1,284
TOTAL	**14,925**

Source: AER regulatory decisions and network planning documents; #: It was not possible to separate customer connections from augmentation capex for NSW distributors with available information.

As shown in Figure 8 below, avoidable network capex (blue wedge) makes up almost one third of all projected network capex over the current five-year regulatory period. This equates to approximately $14.9 billion dollars worth of potentially avoidable network costs over the next five years.

Figure 8: Avoidable network capex relative to total network capex ($m 2010)



Source: AER regulatory decisions and network planning documents; NB: It was not possible to separate customer connections from augmentation capex for NSW distributors with available information.

3.3 Quantifying annual deferral value

The central thesis of this paper, is that if even a portion of the $14.9 billion shown in Figure 8 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 and excluding the value of other benefits such as avoided carbon emissions.

The annual deferral value is derived by first taking the capital expenditure on network augmentation and dividing by the amount of growth in kilowatts (kW) being serviced by the proposed capacity addition, giving a value in $/kW. This is the marginal cost of each additional kW per unit growth in peak demand, or conversely the marginal benefit that could potentially be derived through DE if the constraint can be avoided.

This value can then be "annualised" by calculating the annual value avoided:

- Through eliminating the need to service equity and loans on network capital, using a real "vanilla Weighted Average Cost of Capital" (WACC) of around 7.5% per annum[12]; and adding it to the
- Avoided depreciation, using flat-line depreciation over a network infrastructure lifespan of 40 years (2.5%).

This method results in an annualised value of 10 per cent of the total capital cost. The actual WACC will vary according to economic conditions, however 10 per cent serves as a reasonable rule-of-thumb. When this method is applied using the augmentation expenditure in Table 3 above along with demand growth projections, the results are as shown in Table 4 below. This means that in NSW the large planned network augmentation and only moderate demand growth present significant opportunities for DM, being worth up to *an average of* $344/kVA for each year sufficient DM can be employed to defer that investment. Note the dramatic differences between jurisdictions, in that Western Australia, with far less augmentation expenditure in the current regulatory period, only shows an annual deferral value of up to $83/kVA per annum.

[12] Based on nominal vanilla WACC of 10% (2009e and 2010a Qld and 2009f and 2010b SA Draft and Final AER Decisions on Cost of Capital) adjusted for inflation of 2.5%.

Table 4: Annual value from deferring network infrastructure

	Annual Deferral Value ($/kW/a)
NSW/ACT	344
QLD	206
VIC	110
SA	373
TAS	227
WA	83
NEM AVG	**257**
NATL AVG	**223**

Source: AER regulatory decisions and network planning documents; NB: It was not possible to separate customer connections from augmentation capex for NSW distributors with available information.

4 DANCE Model

4.1 Introduction

The augmentation investment and demand growth data upon which the annual deferral values presented in Table 4 are based, stem from the distribution zone substation or sub-transmission substation level. Thus 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 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, 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 substation level data, enabling the highlighting of ‘value hotspots’ where decentralised energy resources might be applied most cost-effectively.

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 annual reporting and other simple network planning data and creating simple but powerful interactive visual outputs, DANCE has the potential to provide a useful demand side engagement tool for network businesses. By making this information more accessible, **DE service providers** can be assisted in locating the geographical areas and timeframes that they should be looking to develop projects in order to achieve the greatest benefit from their products and services. DANCE also helps to communicate to **policy makers** needing to understand the dynamics of where and how DE can contribute to beneficial economic and environmental outcomes.

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 (Zone substation and Terminal Station) electricity demand data:
  - Current year plus 5-year summer and winter peak demand forecast in MVA for each Distribution Zone Substation and Sub-Transmission Substation (12 data points per substation).
  - 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 substation).[13]
  - The observed peak for each month of the year (12 data points per substation)
- Network capacity information:
  - Secure capacity in MVA in summer and winter (2 data points per substation).
  - The name the of Sub-Transmission station serving each Distribution Zone Substation (≈1 data point per distribution substation).
- Geographic information:
  - Geographic coordinates for each substation (2 data points per substation).
  - Geographic regions of each distribution feeder zone (where available)
- Investment information:
  - Proposed value of preferred network solution for all substations facing a growth-related constraint (1 data point for each substation in which investment is planned).
  - Proposed year of augmentation investment (1 data point for each substation in which investment is planned).

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 7.5% per annum 'real vanilla WACC' is suggested as the default as discussed in Section 3 above.[14]
  - Depreciation value of network assets – the default of 2.5% is calculated as a straight-line depreciation over a 40-year infrastructure lifetime (see Section 3).
  - Discount rate – the default value is 7% based on NSW Government (2007).

[13] Note that these load curves shapes are not consistently publicly available and in many cases need to be sought directly from network businesses. It is for this reason that the mapping images shown in this paper involving 24hr load variations are based on hypothetical load curve shapes for residential, commercial and industrial areas.

[14] For the mapping outputs for NSW shown in this paper, a figure of 6.34% was used, calculated by averaging the AER (2008c) *nominal* vanilla WACC for EnergyAustralia & Integral Energy territories & subtracting an inflation rate of 2.5%.

4.4 Calculation Method

Annual deferral value

Using basic annual peak demand forecast and capacity constraint data, the DANCE Model calculates the available capacity for each substation for a given year, and using the 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.[15] 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 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. Future versions of the model will consider having a dual constraint category if both summer and winter are relevant.

The facility is also provided to add additional Long Run Marginal Costs that stem from the transmission network, further upstream than sub-transmission substations. In the outputs shown for NSW, a calculated $100/kVA/yr (using the LRMC formula above) was added to account for transmission investment of $400 million to address an impending summer constraint (TransGrid & Energy Australia, 2009). This value is applied to all substations within the DANCE Model – providing all are served by the same upstream transmission asset requiring augmentation – as this reflects the fact that DM applied in any of those network service areas could be effective in relieving the upstream constraint.

The outputs of this initial basic annual LRMC calculation are shown in Figure 17 (Section 4.5).

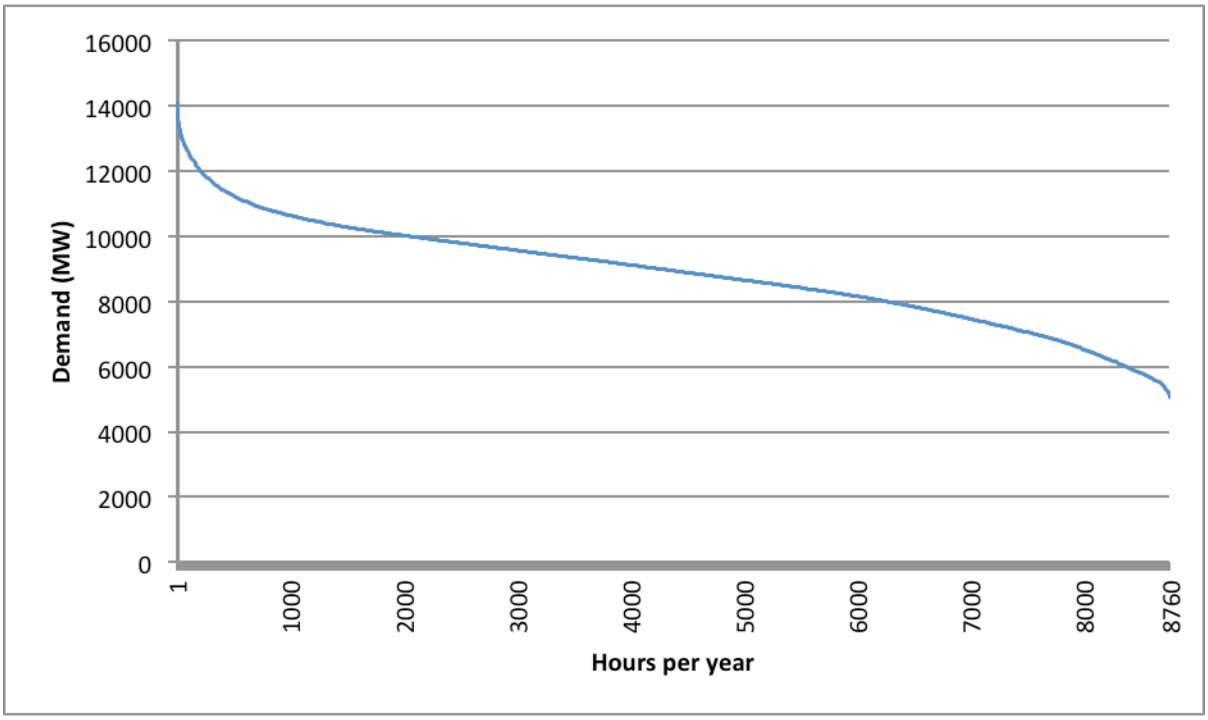
Load Duration Curves

The next time-steps computed by the DANCE Model are variations according to the month of the year and hour of the peak day. To compute this more complicated step, it is necessary to construct a Load Duration Curve by modelling 8760 hours of demand for each substation to determine the number of hours per year demand exceeds a given capacity. Figure 9 below shows an example load duration curve that is based on NSW-wide data. It shows that in the year of analysis (2009) the

[15] 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.

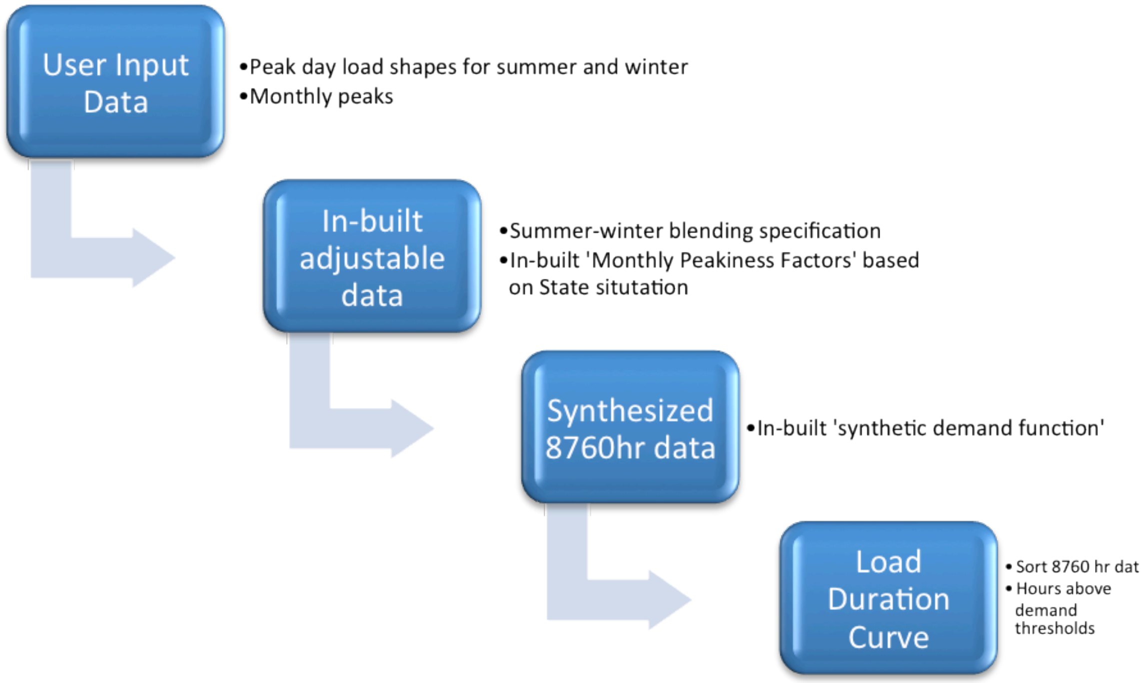
absolute peak was just over 14,000MW, which occurred for around one hour. Looking further down the curve, 12,000MW was only exceeded for around 200 hours in the year, meaning that the top 2,000MW of capacity was required for a total of 200 hours in 2009. At no time did NSW demand go below around 5,000MW.

Figure 9: Example Load Duration Curve for NSW



The process of converting simple user-entered load curves and peak demand data into Load Duration Curves is broadly represented in Figure 10, which illustrates that there are three main conversion stages used in the DANCE Model: deriving monthly peak and average day load shapes; turning this into 8760 hour data; and finally constructing the Load Duration Curves.

Figure 10: Broad input and calculation stages in creating Load Duration Curves



Each stage in the process represented in Figure 10 is now explained in more detail.

Simulating Annual (8760) Hourly Data

To "synthesise" 8760 hour data, in mathematical terms our aim is to specify a function `syntheticDemand(h, d, m, I)`, which, for a particular hour h,[16] day d,[17] month m,[18] and given a vector of user inputs **I** (described further below), will return the hourly demand (in kWh) for that hour. For example, `syntheticDemand(9, 25, 12, I)` would return a the hourly demand between 8 and 9 am on Christmas Day (i.e. the 25th day of the 12th month).

The calculation of synthetic 8760-hour data using the `syntheticDemand` function, requires three user-supplied data and two in-built user adjustable data.[19] The five inputs required are:

- User Input Data:
  - Summer peak hourly profile
  - Winter peak hourly profile
  - Monthly Peaks
- In-built User Adjustable data:
  - Proportion of summer days
  - Average daily peak for each month

These inputs are described below.

[16] h $(1 \le h \le 24)$
[17] d $(1 \le d \le 31)$
[18] m $(1 \le m \le 12)$
[19] Mathematically, these are inputted in the vector **I**

User Input Data – Seasonal Load Shapes and Monthly Peaks: As 8760-hour data is not publicly available from network businesses (and is time intensive to collate for every substation), DANCE uses several relatively simple inputs to "reconstruct" complex annual variations in demand. The inputs used to simulate the 8760 data points are as follows:

1. The observed overall peak for each month of the year (12 data points per substation, denoted **`monthlypeak`** in below formulas)
2. Hourly load curve shapes for the peak summer day (24 data points per substation, denoted **`summerpeak`** in below formulas) and
3. Hourly load curve shapes for the peak winter day (24 data points per substation, denoted **`winterpeak`** in below formulas).[20]

Alternatively to the above peak day and monthly inputs, DANCE also accepts 12 months of hourly demand data, which by-passes the synthesising process. This is appropriate if the model is being applied by an electricity network business, or the network is able to give access to this non-publicly available information.

In-built User Adjustable Data – Summer/Winter Blending Specification: Winter days have higher energy consumption in the morning and evenings, commonly associated with space heating and lighting, while summer days have a stronger afternoon demand driven by air conditioning. While the load curve shapes for Summer and Winter months are generally consistent, Spring and Autumn months can have both hot days and cold days. This is allowed for in the model by allowing each month to have a mix of both summery days (that have an hourly demand profile typical shaped like a summer day) and wintery days (with an hourly demand profile shaped like a winter day).

The Summer/Winter blending specification determines the percentage of days in each month that are shaped based on the summer demand profile, with the remaining days assigned the winter profile. The default values assumed in the DANCE model (as originally specified for Sydney climate zone) are shown in Table 5, but can be changed by the user if desired.

In `syntheticDemand(h, d, m, I)`, the first element of vector I is the relevant summer proportion for the supplied month `m`, and this is denoted **`summerproportion`**. So if `m` is 3 (March) then **`summerproportion`** is 80% (i.e. 80% of days are 'summery', 20% are 'wintery').

Table 5: Default DANCE summer/winter day blending percentages

Month	Summer Day Percentage
January	100%
February	100%
March	80%
April	55%
May	20%
June	0%

[20] Note that these load curves shapes are not consistently publicly available and in many cases need to be sought directly from network businesses. It is for this reason that the mapping images shown in this paper involving 24hr load variations are based on hypothetical load curve shapes for residential, commercial and industrial areas in Sydney.

Month	Summer Day Percentage
July	0%
August	0%
September	20%
October	55%
November	80%
December	100%

In-built Adjustable Data – Average Day Peak Factors: These factors are not entered by the user, and are system wide (i.e. the same for every substation) and are derived from statistical analysis of hourly State-wide National Electricity Market (NEM) load curves. The statistical average day for each month was derived by averaging all 12am January demand values, all 1am January demand values, and so on. The highest peak demand of this statistical average January day was then divided by the actual observed January peak, and so on. So for each month the peakiness factor is a *ratio* that represents the "Average Day Peak as a percentage of Maximum Day Peak". For NSW, these figures are shown in Table 6. Note that February has the lowest Average Day Peak Factor, which means the *difference* between its maximum day peak and average day peak is greatest. This indicates that in NSW, there are greater differences between peak and average days in summer than in winter.

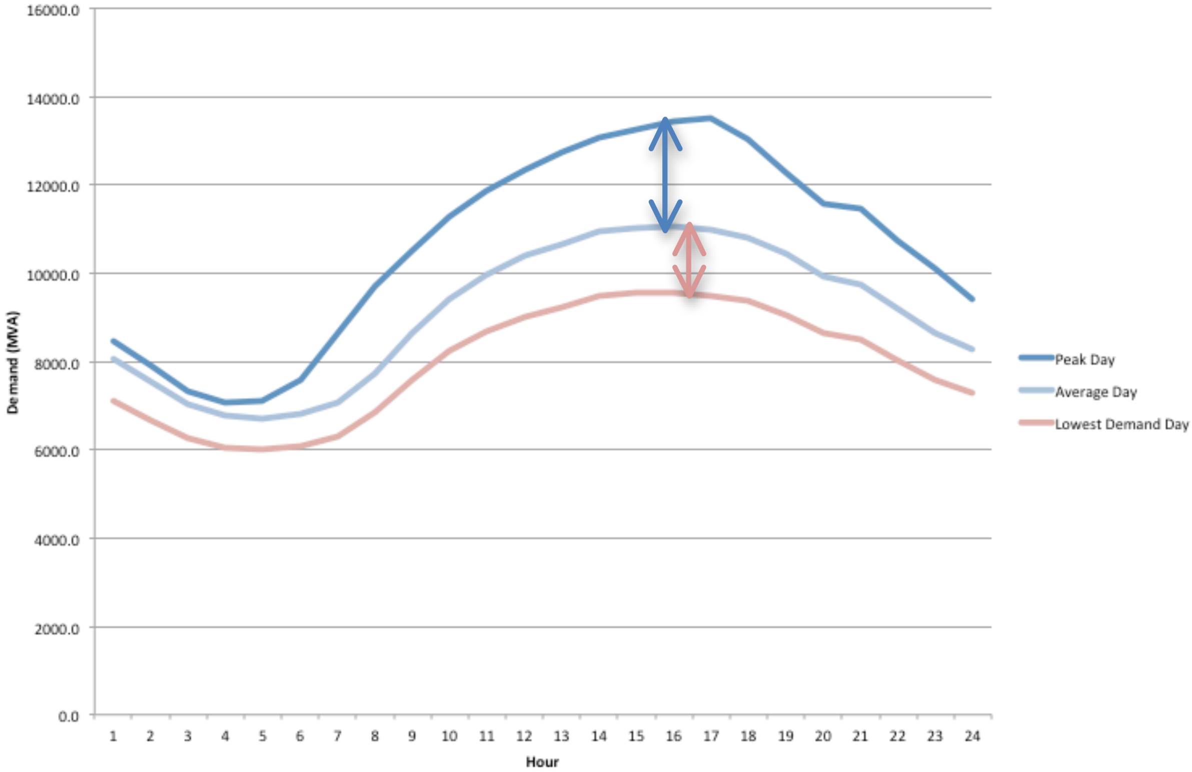
Table 6: Average Day Peak Factors derived from jurisdictional NEM Data

Month	Victoria[#]	NSW*
January	70%	82%
February	78%	77%
March	86%	89%
April	87%	89%
May	92%	94%
June	92%	90%
July	93%	90%
August	92%	90%
September	90%	89%
October	90%	86%
November	77%	83%
December	78%	88%

*Notes: #: Victoria is average of 2008, 2009 and 2010; * NSW is 2009-10 only.*

To create the 8760-hour data it is necessary to synthesize hourly demand not only on peak days, but also on more 'typical' days in that month. Thus the Average Day Peak Factor determines the 'spread' of load curves synthesized for a given month. This is illustrated graphically in Figure 11. The peak day (dark blue) defines the highest demand day in a given month, while the Average Day Peak Factor determines the position of the average day curve (light blue) relative to the peak day curve. The lowest demand days (down to the pink line) are allocated below the average day line, somewhat more compressed than the demand days above the average day, reflecting the nature of demand spread.

Figure 11: Example load curve shape allocation (for NSW; January)



The Average Day Peakiness Factor is the fifth element in the vector **`I`**, and is denoted as **`avgpeakpct`**.

The user can override the system-wide Average Day Peakiness Factor for unusual zone substations that deviate from the State pattern, such as zones that are primarily industrial where demand is less strongly linked to climatic factors. For application of the model in different jurisdictions (climate zones) this "Average Day Peak Factor" should be customised.

Specification of `syntheticDemand` function

The syntheticDemand function takes the above five data inputs, and in one set of macro-based calculations, determines 8760-hour demand across the year. First, the function has to determine where to use a summer or winter profile. Next there are three scaling factors that need to be determined, one each for the hour in the day, day in the month, and month in the year. Finally the equation that determines the synthetic demand for the specified day is determined. These five components will be described individually in the following subsections.

Profile type: There are two possibilities, either the day has a winter profile or a summer one and this is determined by `summerproportion` and the day *d* selected. First, since we know the month *m*, we know the number of days in the month denoted NUMDAYS(*m*). Now consider the fraction *d*/NUMDAYS(*m*) in relation to `summerproportion`.

There are two possibilities, either: *d*/NUMDAYS(*m*) ≤ `summerproportion` or *d*/NUMDAYS(*m*) > `summerproportion`. If *d*/NUMDAYS(*m*) ≤ `summerproportion` then:

- The day is assumed to have a summer profile;
- `peakshape` = `summerpeak`; and
- `maxhourlyenergyuse` = MAX{`summerpeak`}.

Alternatively, if *d*/NUMDAYS(*m*) > `summerproportion` then:

- The day is assumed to have a winter profile;
- `peakshape` = `winterpeak`; and
- `maxhourlyenergyuse` = MAX{`winterpeak`}.

Hour Peak Factor: For each hour in the day, we calculate a factor (ranging up to 1) that specifies how 'peaky' that hour is relative to other hours in the day. That is, the peak hour in the day will have an hourly peakiness factor of 1.0, with other hours below one.

The hour in day factor is denoted `peakynessofhour`, and for a specified hour *h* in the day, the hour in day factor is determined by:

$$\texttt{peakynessofhour} = \frac{\textbf{peakshape}[h]}{\texttt{maxhourlyenergyuse}}$$

Day Peak Factor: In each month, some days will have higher demand than others. We model this by having a factor for each day that specifies how the demand for that day compares to other days in the same month. By definition, the day with the highest demand has a day-in-month factor of 1, with all other days having a factor less than 1.

The day in month factor is denoted *d1*, and for a specified day d in the month m*,* the day in month factor is determined by:

$$\texttt{d1} = \left(\frac{1}{\texttt{avgpeakpct}}\right)^{\frac{d-\texttt{NUMDAYS}(m)}{\lfloor \texttt{NUMDAYS}(m)/2 \rfloor}}$$

The above equation essentially ensures that the middle day in the month has peak demand matching that specified by the user (by the `avgpeakpct` input), while the peakiest day has peak hourly demand matching the monthly peaks (specified by `monthlypeak`).

Monthly Peak Factor: Each month in the year will have more-or-less 'peaky' demand than other months. The month-in-year factor accounts for this. Concretely, the month in year factor is denoted `monthlypeakfact`, and for the specified month m, the factor is determined by:

$$\texttt{monthlypeakfact} = \begin{cases} \frac{\texttt{monthlypeak}}{\texttt{maxhourlyenergyuse}} & \text{if } \frac{\texttt{monthlypeak}}{\texttt{maxhourlyenergyuse}} < 1 \\ 1 & \text{if } \frac{\texttt{monthlypeak}}{\texttt{maxhourlyenergyuse}} \geq 1 \end{cases}$$

Synthetic demand equation: The synthetic demand equation can now be defined as:

$$\texttt{syntheticDemand}(h,d,m,\mathbf{I}) \quad = \quad \begin{array}{l}\mathbf{peakshape}[h]\Big(1-(1-\texttt{d1}).\texttt{peakynessofhour}\Big) \\ \times\Big(1-(1-\texttt{monthlypeakfact}).\texttt{peakynessofhour}\Big)\end{array}$$

Essentially these factors are used to assign an even spread of proportionally adjusted:

- peak day load curves for the highest 15 demand days of the month, between the peak and average day demand curves; and
- average day load curves for the lowest 15 demand days of the month, below the average day demand curve.

Constructing Load Duration Curves

With 8760 hours of data points for each zone substation, it is straightforward to construct a Load Duration Curve (Figure 9). The 8760-hour data is then sorted from highest demand to lowest demand, which then shows the number of hours each year that a particular demand level occurs. The annual maximum peak occurs for one hour, while lower levels of demand are reached more often. This provides the basis for costing the hourly and monthly Marginal Deferral Values.

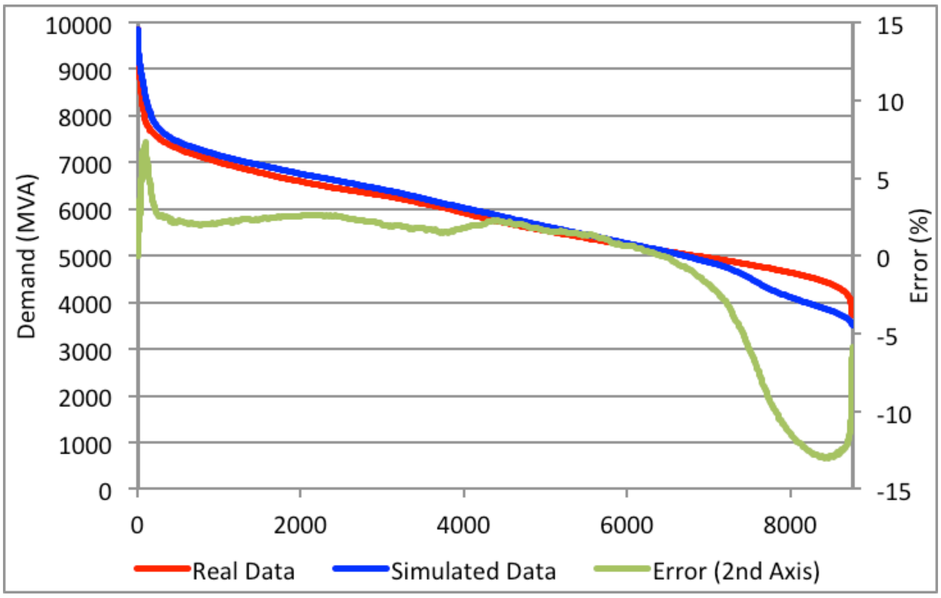
Calibration and Accuracy of Model

The process of reconstructing 8760 hours of data from 60 user-entered data points was performed using publicly available half-hourly National Electricity Market (NEM) data for testing and calibration (initially NSW and later Victorian data). The methodology was thus effectively built around real data, which meant it was possible to quantify the difference between our simplified reconstruction of the Load Duration Curve based on the parameters DANCE requests of the user, and the *actual* Load Duration Curve.

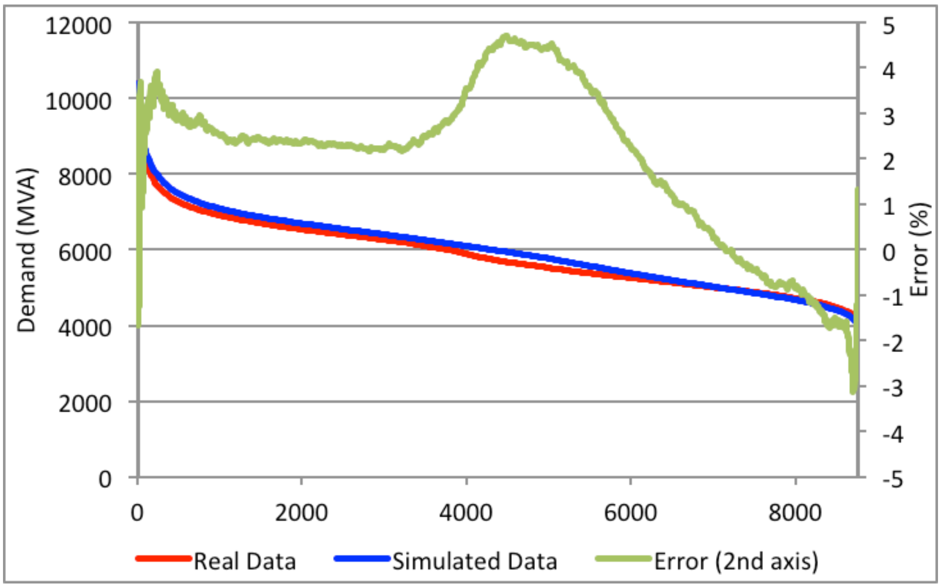
The process as described in this section typically achieves accuracies of ±5% in the top 5000 hours of the year. Figure 13 shows the real Victorian Load Duration Curve in red and the simulated data from DANCE in Blue, with the positive or negative error shown in green against the secondary (right hand) axis. Note with 2008 data being within ±2% accurate, 2009 data within ±5% and 2010 data maintaining a ±3% error, with an exception of the first 300 hours. After 7000 hours the error decreases to 13 and 2.5% for the 2010 and 2008 data respectively. The primary reason for this error is that the minimum (overnight) values on “lowest 15 demand days” of summer months are brought down too far using the Peak Shape Allocation Factor. However, this error is not of any consequence as the infrastructure implications with which DANCE is concerned are confined to the top one percent of the year. In most cases the top 10 hours are of most importance.

Figure 12: 8760-hr Load Duration Curve Accuracy Check using Victorian data for A) 2010, B) 2009 and C) 2008

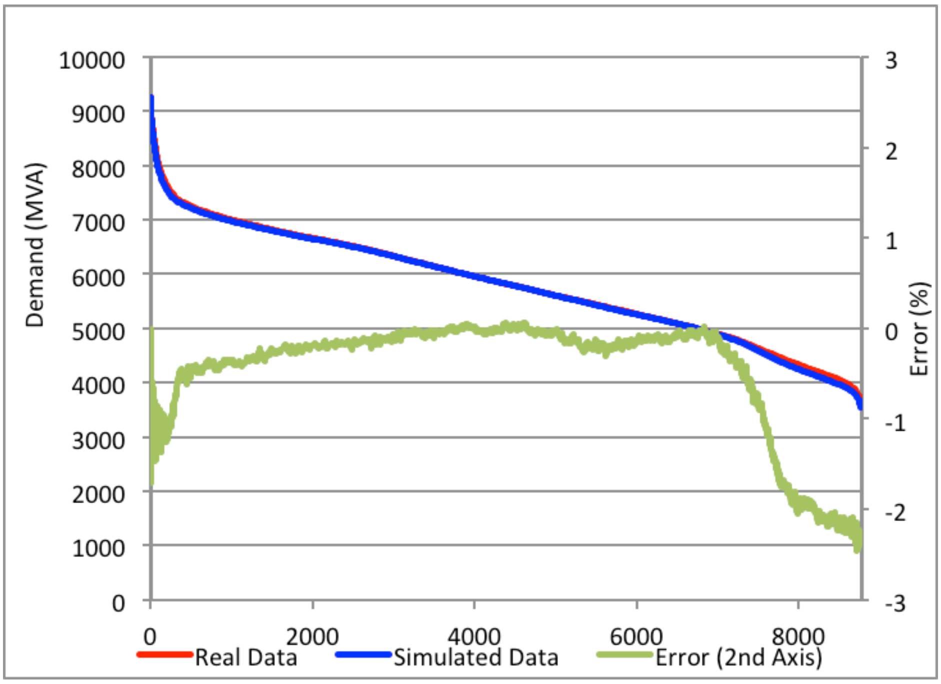
A) 2010



B) 2009



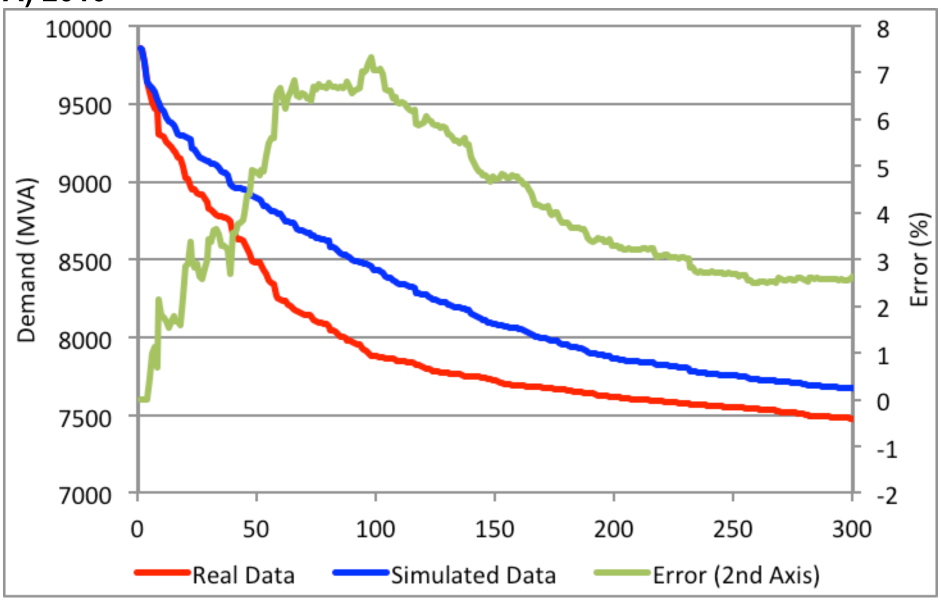
C) 2008



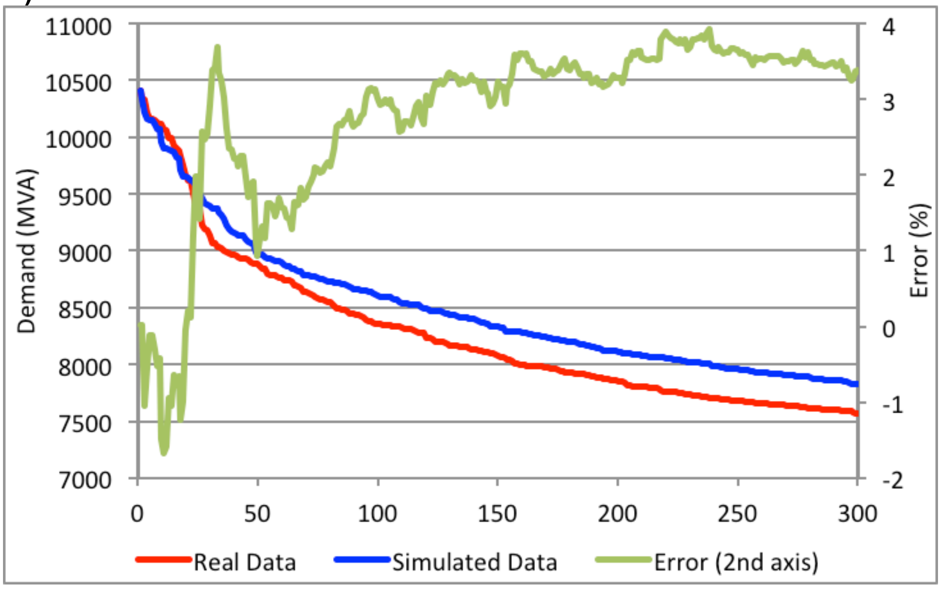
Examining the accuracy of the top 300 hours of demand, we observe different results for the different years of data. In 2008, the data is consistently within ±2% error, and with the exception of 1 data record within ±1.5%. In 2009, the data for 0-20 hours is within ±2% error but thereafter rises, and settles at between 2-4% error for the top 150-300 hours. 2010 has the lowest accuracy, with the error rapidly rising to just under 7% for the hours 60-100, before eventually declining to be under 3% from 235 hours onwards. It may be possible to improve on this error through methodological adjustments in later versions of the DANCE Model.

Figure 13: Top 300-hr Load Duration Curve Accuracy Check using Victorian data for A) 2010, B) 2009 and C) 2008

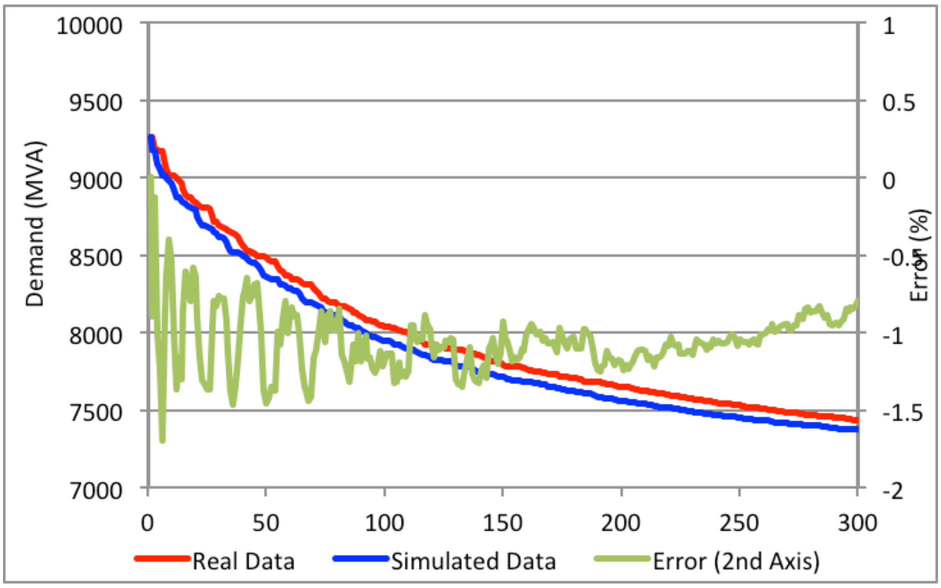
A) 2010



B) 2009



C) 2008



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:

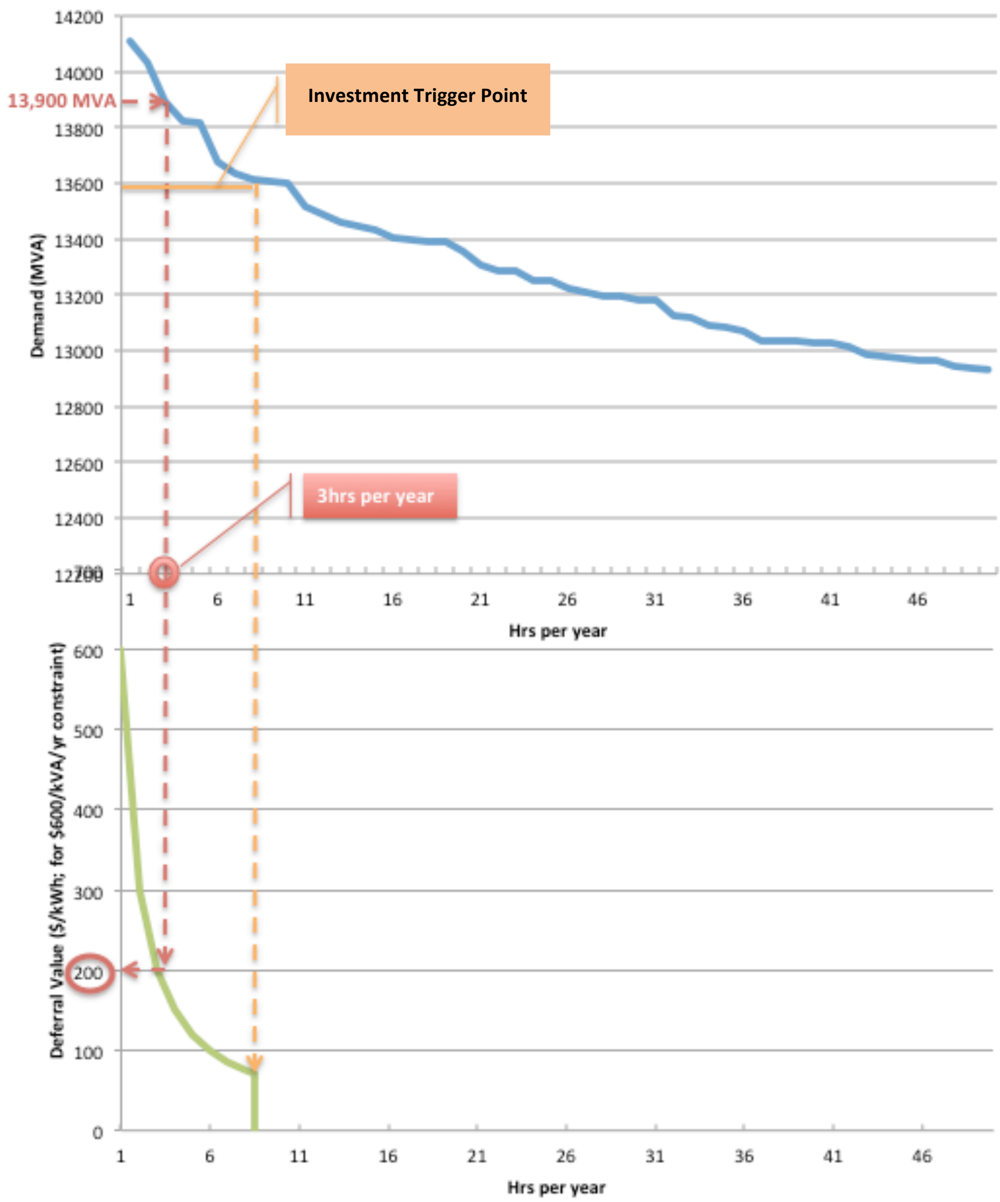
$$\boldsymbol{Hourly\ Deferral\ Value_{(Time\ of\ Day)}} = \frac{\$/kVA}{yr} \div \frac{hrs}{yr} = \frac{\$/kVA}{\cancel{yr}} \times \frac{\cancel{yr}}{hrs} = \$/kWh$$

(If we assume that kVA = kWh, 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 14 below explains this process graphically. After constructing the Load Duration Curve, the DANCE model reads off the hours per year associated with a particular level of demand, and then references this point on a cost curve of deferral value. The example shown by the red dotted line in Figure 14 is for a particular hour at of the day at which the demand is around 13,900 MVA. This demand is above the DE Restore 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 14.

Figure 14: Conceptual diagram of Hourly Deferral Value calculation



This method is applied for the demand at every hour of the day on key peak days in summer or winter to map the variation across a critical 24-hour period.

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 original version of the DANCE model used to create the GIS Maps shown below and in the Caringbah Study shown in Figure 20 and Table 7, 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.

As in practice this is unlikely to be strictly true, the later revision of DANCE applied in Langham *et al.* (2011) assesses the hourly and monthly deferral values at each level 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.

GIS Mapping

The data from the Excel DANCE Model is then exported in simple tabular format to a Geographical Information System (GIS). The research team used the ArcGIS 9 package, however the operations could be performed on other GIS platforms.

For each of the outputs (detailed in the following section), the data for each substation is displayed at its relevant geographical location. For outputs that require a continuous "surface" (i.e. all outputs except for Total Investment), an interpolation is performed to assign values to other geographical areas to represent the coverage of different substations. In this work, the actual network service territory boundaries were not publicly available, so instead the geographical midpoint between substations was used as a proxy. This was done through the use of a 'kriging' interpolation technique to a high power, which makes the transition between different substation boundaries sharper than a gradual transition that would be achieved through other interpolation methods.

The DANCE Model has also more recently been applied to Victoria (for further information see Langham et al. 2011), where available capacity and marginal deferral values were defined according to actual distribution zone substation boundaries rather than approximations based on their geographical location alone.

4.5 Outputs

The DANCE Model spreadsheet exports key data in a simple format for importation into a Geographical Information System (GIS). In the original version of DANCE the output maps are produced as image files, as shown in this section, and **are available on the iGrid website as a freely downloadable interactive Powerpoint Slideshow.** In the more recent application to Victoria (for further information see Langham et al. 2011), **Google Earth** has been used as the interactive user platform to allow greater user interrogation of underlying data and improved spatial referencing.

There are five primary GIS mapping outputs from DANCE:

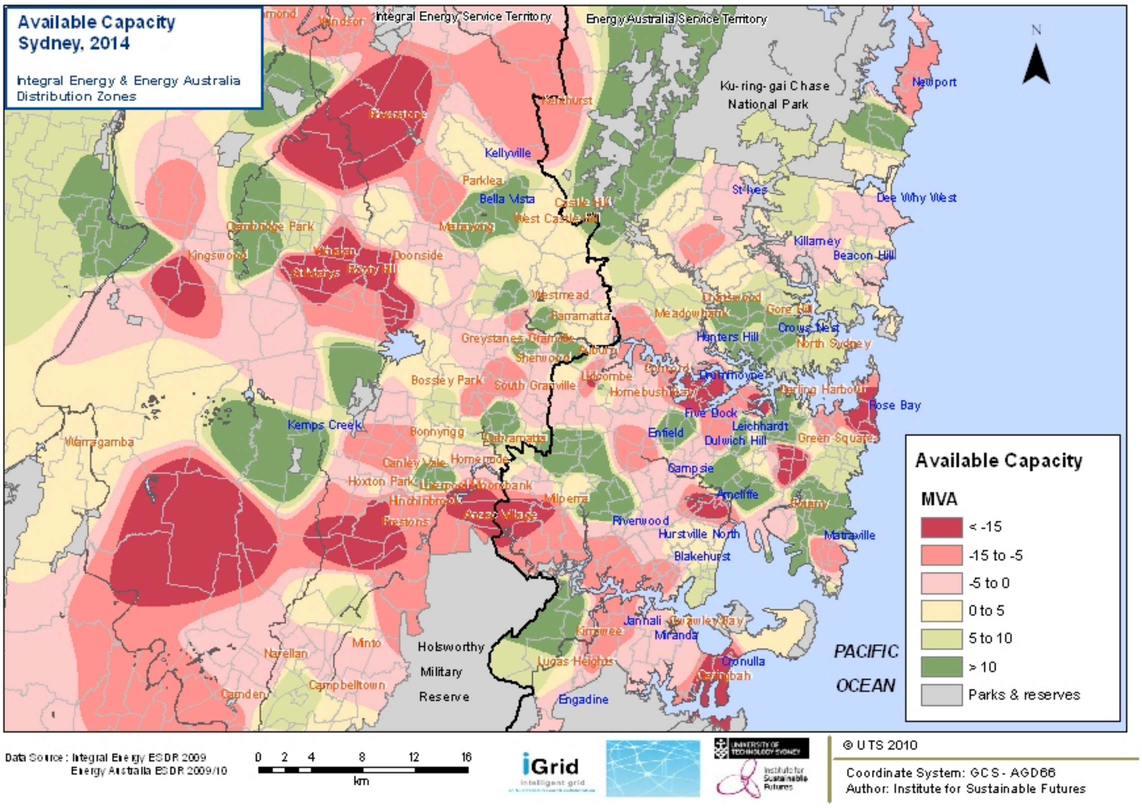
1. Available capacity
2. Total investment
3. Annual marginal deferral value in effective peak season ($/kVA/year)
4. Monthly marginal deferral value across the year ($/kVA/year)
5. Hourly marginal deferral value on key constraint day/s ($/kVA/year)

Available capacity

The map of available capacity is produced for the distribution zones substation level only, and is shown in Figure 15. This is essentially a map of 'firm capacity' according to the relevant reliability criteria and capacities as of 2009, minus the forecast peak demand in 2014. The green and yellow colours indicate distribution zones that have sufficient spare capacity in 2014, while the pink and red colours indicate distribution zones facing growth-related constraints where investment will be needed to ensure reliability is maintained. The colour of the substation label indicates whether it is a winter (blue) or summer (orange) constraint.

Ideally this image and all others presented in this section would be produced using distribution zone service territory boundaries, however this information was not publicly available for the Sydney metropolitan area. Instead an interpolation method was used such that the geographical midpoint between two substations was effectively used as the proxy for service territory boundaries.

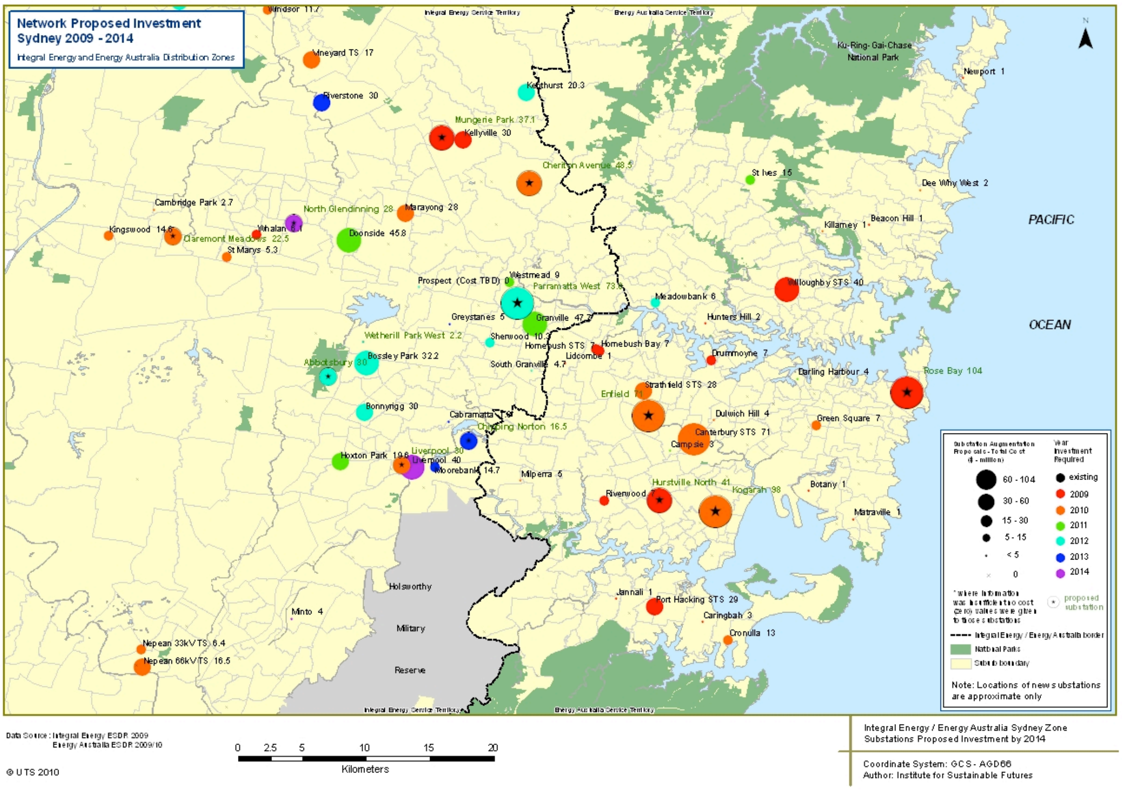
Figure 15: Available Capacity (MVA)



Total Investment

Figure 16 shows the total investment in network augmentations between 2009 and 2014, as reported in annual planning documents. The size of the dots indicates the magnitude of investment, ranging from around $1-2 million up to $104 million for a new zone substation in Rose Bay on the south side of the opening to Sydney harbour. The colour of the dots indicates the year of planned investment. This is the year in which DM would need to be delivering the demand reductions sufficient to overcome the constraint. Zone Substations with a star inside the circle and a green text label are proposed new zone substations, which tend to be the largest investments in the network.

Figure 16: Total Investment in Network Augmentation



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 (see Section 3.3 above), we can produce a map showing Annual Marginal Deferral Value (Figure 17). Areas with neutral colours in Figure 17 are those with limited to no deferral value, while marginal deferral value increasing strongly towards the brown and purple categories ($300-1000/kVA/yr). Take an example of a 2MW cogeneration operator being set up in a purple constraint region and contractually providing firm summer peak power reduction on demand as required by the network business to successfully defer the construction of new network infrastructure. The potential maximum value of this firm peak demand reduction to the network would be calculated as follows:

Annual Deferral Value ($/kVA/yr) x Annual Growth Rate (kVA) x Years of deferral

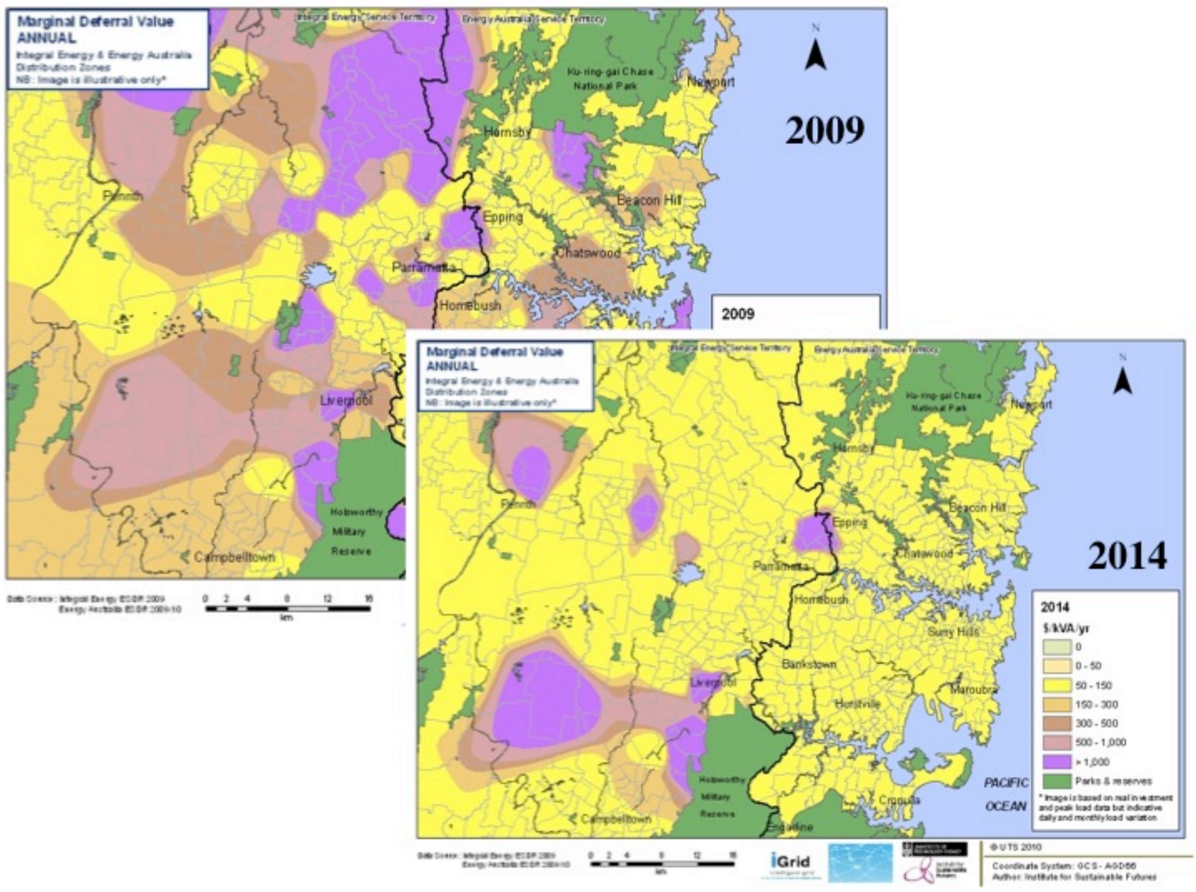
In a purple constraint region, the annual deferral value is $1000/kVA/yr. A 2MW generator would offset peak load by around 2.5MW after taking account of the waste heat providing additional cooling load offset. If at this zone the annual growth rate is 1.25MVA (1250kVA), this translates to two years of growth deferral. Using the above formula:

$1000/kVA/yr x 1250kVA x 2yrs = $2.5 million

Ultimately in a competitive market environment the network will probably not pay this full value, but rather seek the minimum value that the market will bear. As the value paid by the network to alleviate the demand growth is less than the cost of the network option, the costs to the network business is lower, which is eventually passed on to consumers in the form of reduced network charges through lower network expenditure.

Note in Figure 17 that in 2009 (left) there are many regions where cost-effective DM opportunities are available. By 2014 (right), 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 2014 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 2014 than in 2009.

Figure 17: Annual marginal deferral value for 2009 (left) and 2014 (right)



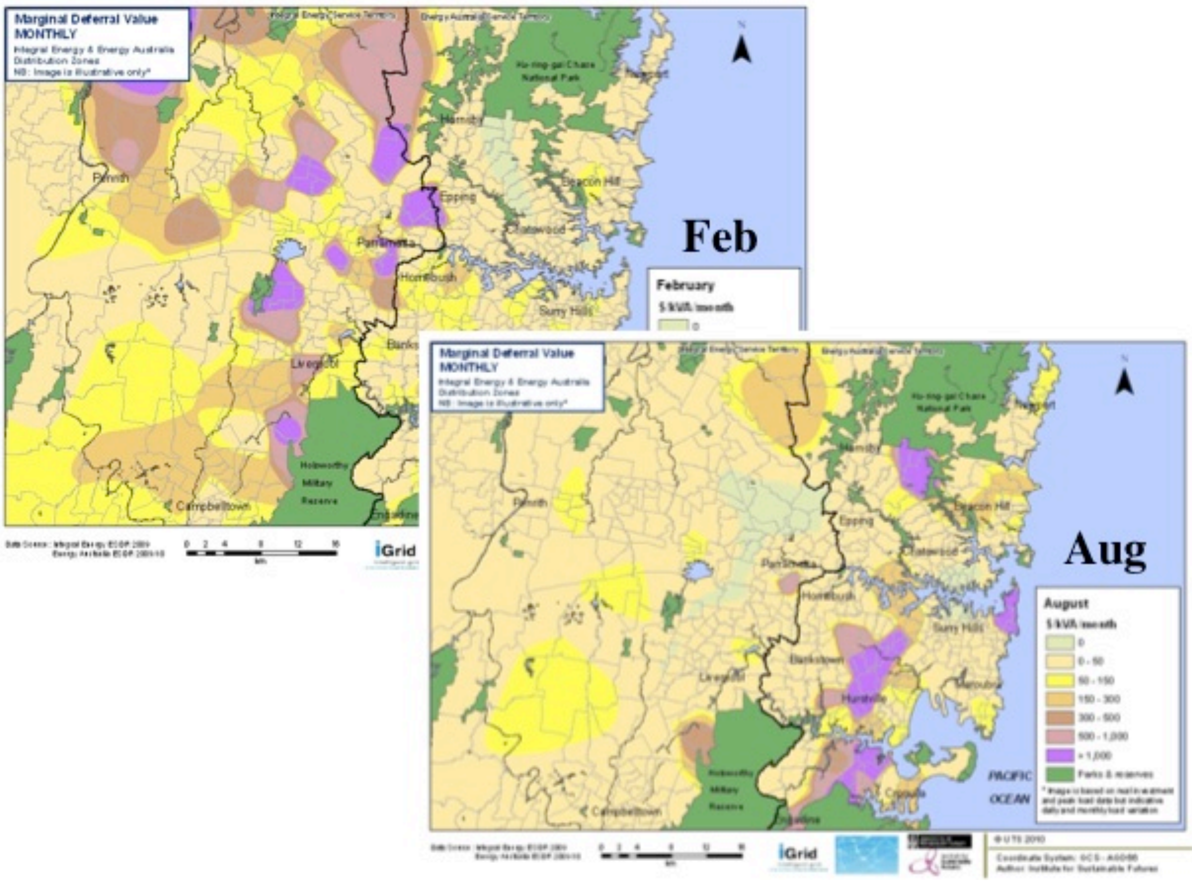
Monthly Marginal Deferral Value

By going further and breaking down the annual deferral value into the monthly values in which those constraints are occurring, we can see the seasonal variation affecting different geographical regions. Figure 18 shows two examples of the monthly deferral value map, for February and for August (both in 2009). The category classes are the same as for annual deferral value, only the units differ, this time in $/kVA/month instead of per annum. Note that as constraints often only happen in one or two key months per year, the actual monthly $/kVA values are of the same magnitude as the annual

$/kVA values. That is, most of the deferral value is in fact tied up in one or two months per year, while other months show deferral values close to zero.

While the outputs shown in Figure 18 are illustrative only, in that monthly peak demand values for each substation are based on the NSW-wide figures (due to lack of data), there are some interesting differences to note between February and August deferral values. In February, many of the constraints are occurring in western Sydney, where summer air conditioning loads are high; while in August the constraints occur primarily in the eastern (coastal) suburbs, largely reflecting the milder summer climate due to the sea breeze.

Figure 18: Monthly marginal deferral value for February (left) and August (right)



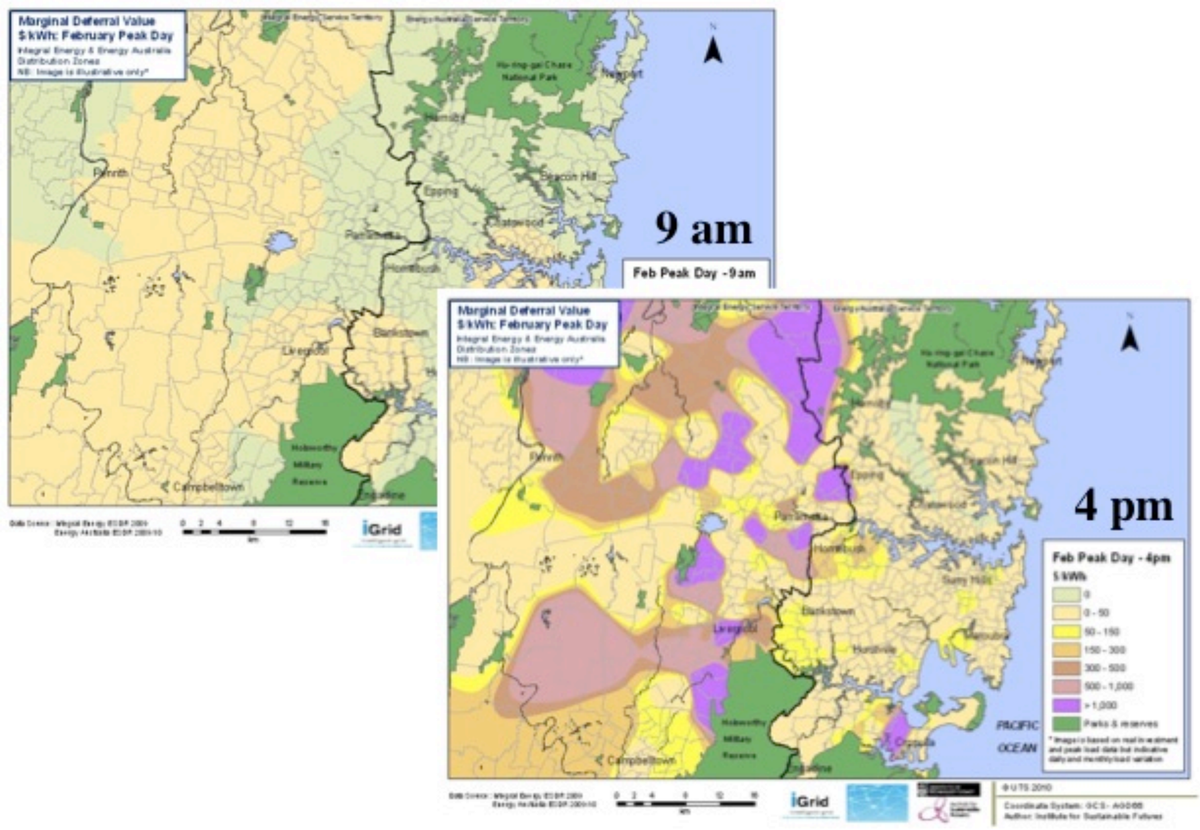
Hourly Marginal Deferral Value on Peak Days

By going further again to break down the deferral value into the hourly timeslots on key peak days in which those constraints are occurring, we gain insights into the types of electrical loads driving the constraints (e.g. air conditioning drives constraints later in the afternoon, which lighting occurs later in the evening), and how short the constraint periods actually are driving the billions of dollars of investment outlined in Section 3.2. Figure 19 shows two examples of the hourly deferral value maps, for 9am and 4pm respectively on the February peak day for 2009. Again, the category classes are the same as for the annual and monthly deferral value maps, only the units differ, this time in

\$/kVA/hour, or \$/kWh[21] – the most common unit of energy billing. This analysis reveals that even in constrained zones with lower deferral value, we are seeing figures of \$300/kWh – 1,500 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 limitations of current time of use tariffs (at \$0.40) for accurately conveying to consumers price signal to reduce demand.

It is practically and politically impossible for truly cost reflective pricing to be realised at the values shown in Figure 19. Providers of non-network solutions that alleviate a constraint by reducing peak demand at a particular facility may obtain benefit to some degree if they are offsetting standard tariffs, 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.

Figure 19: Hourly marginal deferral value for 9am (left) and 4pm (right) on the February peak day



[21] Mathematically \$/kVA/hr is the same as \$/kVAh, which is roughly equivalent to \$/kWh assuming the 'power factor' is close to 1.0.

To step through the deferral value calculation process and to show how the hourly deferral value plays out over the course of the annual peak day, it is useful to take a case study of a representative distribution zone substation. Caringbah Zone Substation has been selected as a region of high investment and moderate growth. The steps involved in calculating the annual deferral value using the method described Section 3.3 are highlighted in Table 7 below, showing the separate calculation of distribution and transmission deferral values after factoring in investment values and annual load growth.

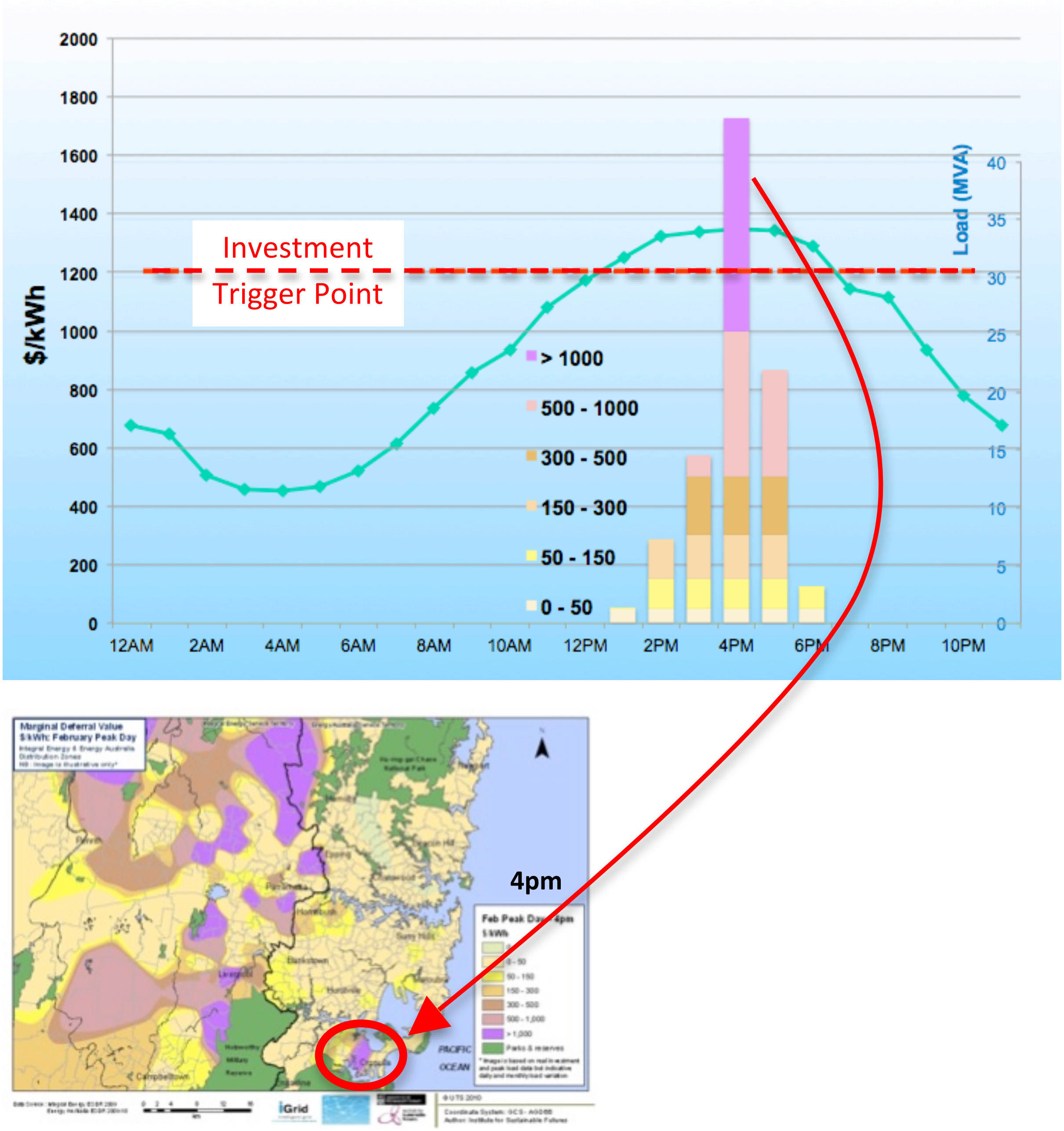
Table 7: Case study – annual deferral value at Caringbah Zone Substation

Proposed Investment (Distribution):	$3 million
Distribution Annual Deferral Value ($/yr)	8.8%[22] x $3m = $265,000/yr
Annual Load Growth	1,300kVA/yr
Distribution Annual Deferral Value ($/kVA/yr)	$204/kVA/yr
Proposed Investment (Transmission)	$29 million
Transmission Annual deferral value ($/kVA/yr)	$1,424/kVA/yr
Annual Deferral Value (Distn + Trans)	**$1,728/kVA/yr**

Figure 20 shows a simplified illustration for Caringbah Zone Substation of how the load on the peak day relates to the Investment Trigger Point, and the hourly deferral value as it shown appears in Figure 19. This substation demonstrates a typical summer peak day load curve for a residential area with reasonable penetration of air conditioning, with demand rising steadily throughout the day and peaking at between 3-6 pm (the green line, using the scale on the right hand side). With a Investment Trigger Point of around 30 MVA (dotted red line), this level is exceeded for a period of 6 hours, from 1pm to 6pm. As the magnitude of that exceedance increases, so too does the marginal deferral value, as higher demands occur for a shorter period of time. By taking a value of $1,728/kVA/yr and spreading this across the hours of the year in which the Investment Trigger Point is exceeded, the peak value reached in the single highest hour is $1,728/kWh, as shown occurring at 4pm in Figure 20 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.

[22] This is lower than the 10% figure explained in Section 3.3, due to the lower WACC used by the AER in the NSW regulatory decision.

Figure 20: Case study – Caringbah zone substation deferral value on peak February day



4.6 Limitations

One of the main limitations of the current analysis lies in reliability of publicly available data. This project has revealed that the investment approved in the AER regulatory is not necessarily all reported in the annual planning reports. Energy Australia, for example, has $8.1 billion of total capital expenditure approved by the AER, including $3.3 billion of growth related capital expenditure (AER 2009b), yet the total investment outlined in the annual planning reports is less than $1 billion

(EnergyAustralia 2009). No expenditure is reported for works within the Sydney CBD, despite being home to around $1 billion of growth-related and security of supply related investment. Integral Energy, on the other hand, have a somewhat better match, with AER approved growth-related capital expenditure of $1.38 billion, and $1.05 billion of that investment shown in its 09-10 planning report (Integral Energy 2009).

This is a valuable exercise to go through to determine whether all relevant opportunities for investment deferral are in fact being reported. Clarification will be sought from network businesses as to the reasons for this mismatch. While such discrepancies may reflect investment decisions that have already been committed, they again highlights both the importance of having data that is a comprehensive as possible and the likelihood that the above analysis understates the full potential value of DE.

4.7 Future DANCE Model development

Some of the potential developments from the current version of the tool beyond the iGrid project include:

- Further development of substation-level information for the user to analyse the kind of network constraint that needs to be addressed, to feed into an assessment of the type of DE applications that may appropriate;
- Adding the ability to consider how networks are able to adaptively manage peak demands through 'offloading' demand onto nearby connected Zone Substations; and
- Integrating the DANCE principles into electricity network business management tools and systems, more explicitly incorporating the probabilistic considerations of network planning.

To see the latest application of the DANCE Model to Victoria, see Langham *et al.* (2011).

5 Conclusion

This paper outlined the magnitude of the economic savings that can be tapped through Decentralised Energy in the context of Demand Management to avoid or defer electricity network constraints, and presented a tool designed to illustrate "where" and "when" Decentralised Energy can be most effectively applied.

Of the $47 billion of electricity network capital investment planned for the next five years, about one third, or $14.9 billion, is potentially avoidable if peak demand growth trend could be eliminated. This presents a large pool of potential value that could be efficiently invested in measures that reduce peak demand and moderate electricity prices in the medium-term, while also reducing energy consumption and greenhouse gas emissions. While much of this network investment is likely to be committed soon to address imminent constraints, the pattern of major investment in infrastructure to support a few hours of demand per year will continue as long as the traditional strong focus on 'supply side' network solutions is continued and regulatory and policy incentives are biased in this direction to tap these potential savings effectively, it is necessary for electricity network businesses, regulators, consumers and providers of Decentralised Energy to understand better the location and timing of network constraints with sufficient lead to develop 'non-network options' to avoid those constraints. The DANCE Model has been created to assist in this effort, to better communicate the task at hand to a wider variety of stakeholders, in an effort to achieve the Decentralised Energy 'trifecta' – lower demand, lower prices and lower emissions.

The details and costs of the specific Decentralised Energy options that can achieve these three parallel and complementary outcomes are outlined in Working Paper 4.3, and cover the areas of energy efficiency, load management and distributed generation. Key policy tools required to unlock this potential – such as cost reflective peak pricing and national targets, obligations and reporting relating to peak demand or infrastructure savings – are outlined in Working Paper 4.2.

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Feedback

This document is a working paper upon which comments and suggestions are welcomed. Some suggestions as to specific areas of feedback that the research team would find valuable are:

- How could the outputs of this model be amended to be of most value to utilities, policy makers, or DE providers?
- Are the data inputs reflective of the available information within/from network businesses?
- Does DANCE contribute more than is already possible within the planning tools available in utilities?

- Are there other features of the tool that you think could be added to enhance its usefulness?
- Is your organisation interested in partnership opportunities to apply DANCE to your area or region?

To submit comments or talk to the research team, please contact the authors at the Institute for Sustainable Futures.

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