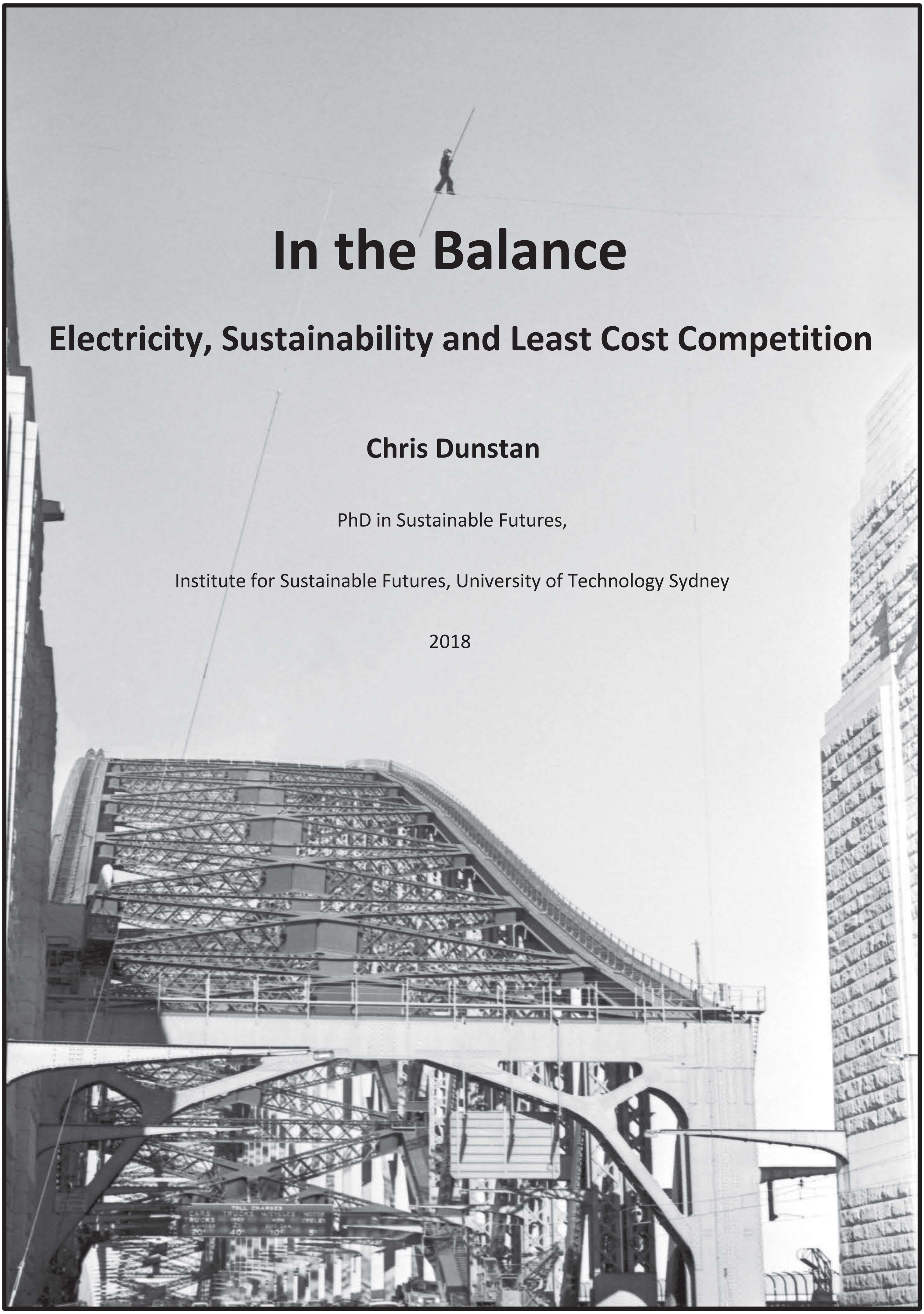

In the Balance

Electricity, Sustainability and Least Cost Competition

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Cover image:

Philippe Petit above the Sydney Harbour Bridge, 3 June 1973 (Fairfax Syndication)

Certificate of Original Authorship

I, Christopher Gerard Dunstan declare that this thesis is submitted in fulfilment of the requirements for the award of a PhD in Sustainable Futures in the Institute for Sustainable Futures at the University of Technology Sydney.

This thesis is wholly my own work unless otherwise referenced or acknowledged. In addition, I certify that all information sources and literature used are indicated in the thesis.

Signature of student

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Acknowledgments

A key strength of my PhD research is its links with a number of collaborative research projects that I have led and been involved in since beginning my PhD in 2005. These include projects undertaken for a range of clients through the Institute for Sustainable Futures (ISF) and the Australian Alliance to Save Energy (A2SE), and in particular, the work program of the CSIRO Intelligent Grid Research Cluster ("iGrid").

The Intelligent Grid Research Cluster involved seven projects from five Australian universities over three years 2008–2011. The Cluster was established through the Collaborative Fund of the CSIRO Energy Transformed Flagship, within its Low Emissions Distributed Energy Theme.

In early 2006, I proposed to CSIRO to undertake several key components of my PhD research as part of the iGrid Research Cluster. This proposal was accepted by CSIRO and formed one of seven parts of the iGrid research program. This research program involved researchers from CSIRO and five universities: the University of Queensland, Queensland University of Technology, the University of South Australia, Curtin University and the University of Technology Sydney. I am grateful to Professor Anthony Vassallo and Professor Stuart White for their work in coordinating the application proposal for the iGrid Research Cluster. I also gratefully acknowledge the support for this project provided by the CSIRO Energy Transformed Flagship.

The Research Cluster ran from late 2007 to late 2011. My PhD supervisor, Professor Stuart White was the overall leader of the research cluster. I wish to thank Ms Louise Boronyak who was the very capable executive officer for the cluster. I led Project 4 of the Research Cluster on "Institutional barriers, stakeholder engagement and economic modelling".

IGrid Project 4 comprised five streams as follows:

1. a review of the benefits of and barriers to the development of Intelligent Grid and its components
2. a report of economic regulatory barriers to Intelligent Grid development and mechanisms to overcome them
3. a deliberative utility and customer engagement process to address cultural and perceived technical issues regarding the development of Intelligent Grids
4. development of an avoidable network infrastructure cost analysis model
5. development of a robust and transparent decentralised energy evaluation model.

Each of these streams comprised an element of my PhD work program.

The research outputs from the iGrid research cluster included two complex models, a series of working papers and a final report, the Australian Decentralised Energy Roadmap (December 2011). These reports are included in the list of related publications, below.

In addition to the iGrid Cluster, I had a leading role in another major research program which contributed to my PhD, A2SE's research program, *Scaling the Peaks: Demand Management and Electricity Networks*. I led two research projects for this program, which contributed to my PhD research: the *Survey of electricity demand management in Australia* and the *Barriers to demand management: a survey of stakeholder perceptions.*

The steering committee of the A2SE research project on the *Potential for energy efficiency, demand side management and distributed generation in electricity network planning*, for which the survey was undertaken, provided me with invaluable advice and feedback, as did colleagues at Energetics Pty Ltd, Energy Futures Australia and Climateworks Australia.

A2SE (now the Australian Alliance for Energy Productivity – A2EP) is a not-for-profit coalition of prominent business, government, environmental and consumer leaders. They have come together to raise the profile of energy efficiency and to ensure that the best possible information on energy is available.

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In each of these research projects, I led in the development and execution of the research, but I also relied on major contributions from many stakeholders, particularly my research collaborators who are listed as co-authors for each of the reports which contributed to this thesis. Without the contributions of these colleagues, the projects would not have been possible. The following chapter-by-chapter acknowledgments outline the contributions of my collaborators.

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Chapter 2 draws heavily on the D-CODE model development that I led for the Intelligent Grid Research Program. I wish to thank my collaborators in the development of the D-CODE model and my co-authors of the D-CODE Report – ISF colleagues: Chris Cooper, John Glassmire, Nicky

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In undertaking and documenting the ***Survey of Electricity Demand Management in Australia (SENDMA)***, I was greatly assisted by two ISF colleagues, Nicole Ghiotto and Katie Ross. Nicole and Katie assisted in the design of the survey instrument, engaging with network businesses to encourage participation, collating data and writing the final report that this chapter draws on.

The SENDMA survey would have been impossible without the support of the electricity network businesses and their staff who took the time to provide data for the survey. I would also like to thank those who provided financial support for the project including the New South Wales Office of Environment and Heritage, and the Victorian Department of Primary Industries and the Consumer Advocacy Panel.

The support of the Queensland Office of Clean Energy; the Northern Territory Office of the Chief Minister; the South Australian Department of Transport, Energy and Infrastructure; the New South Wales Minister for Energy, Mr Paul Lynch; and the Federal Parliamentary Secretary for Climate Change and Energy Efficiency, Mr Mark Dreyfus is also gratefully acknowledged.

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I am especially indebted to Ed Langham who was the project manager for the DANCE model and the Network Opportunity Mapping Project since the project's inception in 2008. Ed was instrumental in shifting the model to become an interactive online tool, which has greatly expanded its reach and functionality. The ongoing success of this project is to a large degree due to Ed's project management and stakeholder engagement skills.

I also wish to thank CSIRO, Data61 and the Australian Renewable Energy Agency, the NSW Government Department of Trade and Industry, Ergon Energy who have contributed funding to the model development. The development of the DANCE model through its application to network planning was also supported by Sustainability Victoria and assisted through cooperation with Victorian network businesses, Citipower–Powercor, Jemena Electricity Networks, United Energy Distribution and AusNet Services. I gratefully acknowledge the support for this project provided by the CSIRO Energy Transformed Flagship.

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Sections 5.4 to 5.6 of Chapter 5 draw heavily on the Intelligent Grid barriers report*: Institutional barriers to intelligent grid: working paper 4.1*. I wish to thank my ISF co-authors of this report, Jane Daly, Ed Langham, Louise Boronyak and Jay Rutovitz for their research for this project and their written contributions to the report.

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I also wish to express my appreciation for the guidance and advice of the steering committee of the Australian Alliance to Save Energy (A2SE) Research Project on the *Potential for energy efficiency, demand side management and distributed generation in electricity network planning*, for which this survey was undertaken. Thanks are also due to my project colleagues at Energetics Pty Ltd, Energy Futures Australia and Climateworks Australia who assisted in the survey.

Chapter 6

Chapter 6 is largely drawn from the report: *20 Policy Tools for Developing Distributed Energy.* I conceived, proposed, planned and directed this project as part of my doctoral research under the auspices of the CSIRO Intelligent Grid Research Program Project 4. However, in undertaking this project, I was very ably assisted by my ISF colleagues. I gratefully acknowledge the very valuable contributions of Edward Langham, Katie Ross and Nicky Ison who collaborated in researching the study and in writing the report.

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I gratefully acknowledge the support for this project provided by CSIRO Energy Transformed Flagship. This chapter also draws on related research undertaken for Sustainability Victoria, the Independent Pricing and Regulatory Tribunal of NSW and the City of Sydney. I express my appreciation for the staff of these organisations for their support and constructive feedback on the research.

Other chapters

While I drew on a range of sources and influences, including from the other chapters, the remaining chapters, 1, 7, 8 and 9, were entirely researched and written by myself independent of any collaborative research projects, except as referenced in the text.

Special thanks are due to Dr David Crossley. David has not only been a leading pioneer and inspiration in demand management in Australia and globally, but has also been a generous and reliable source of wisdom and advice to me on matters demand management related and well beyond throughout this doctoral research.

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List of key related publications:

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Glossary/Key terms

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
capex	capital expenditure
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DANCE	Dynamic Avoidable Network Cost Evaluation (model)
D-CODE	Description and Cost of Decentralised Energy (model)
DE	Decentralised energy (a.k.a. distributed energy) 'Decentralised energy' means electricity generation and management of energy use applied at or near the point of energy use. Decentralised energy includes distributed generation, load management (including energy storage) and energy efficiency technologies and practices.
DG	distributed generation
DER	decentralised energy resources
DM	demand management Electricity demand management means deliberate action by those responsible for electricity supply to reduce or shift demand for electricity, as an alternative to providing supply to meet that demand.
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
DR	Demand Response
DRM	Demand Response Mechanism
DSP	Demand-Side Participation
energy services	'Energy services' are the benefits provided by the use of energy, such as transport, cooking, illumination and heating and cooling. 'Energy services' recognises that unlike many other goods such as water, food, shelter and clothing, energy does not offer direct benefits in consumption.
ENA	Energy Networks Australia
FCAS	Frequency Control Ancillary Services
gentailer	integrated electricity generation and retail company

GIS	geographical information system
IPART	Independent Pricing and Regulatory Tribunal (of NSW)
IRP	Integrated Resource Planning
LCC	least cost competition
LCP	least cost planning
LRMC	long-run marginal cost
MPC	maximum price cap
MRL	minimum reserve limit
MW	megawatt
MWh	megawatt hour
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NSP	network service provider
NSW	New South Wales
opex	operating expenditure
participant test	one of the metrics for assessing options in Least cost Planning, along with RIM test, TRC test, Societal cost test and PACT or UCT
PACT (or UCT)	Program Administrator Cost Test (a.k.a. Utility Cost Test)
RAB	regulatory asset base
RERT	Reliability and Emergency Reserve Trader
RIM test	Ratepayer Impact Measure test
RIT-D	regulatory investment test for distribution
RIT-T	regulatory investment test for transmission
RVT	Resource Value Test
S(C)T	Societal (Cost) Test
TNSP	transmission network service provider
TRC test	Total Resource Cost test
ToU	time of use
TUoS	transmission use of service

Abstract

This thesis assesses the potential to enhance economic efficiency and environmental sustainability by reconciling the principles of least cost planning with the competitive electricity industry. The thesis proposes a novel balanced approach of ‘least cost competition’. Least cost competition aims to encourage both more effective competition in delivering energy services, and better alignment of industry practice with the public interest.

The thesis makes the case for adopting this approach through the following steps:

1. developing an innovative Description and Cost of Decentralised Energy (D-CODE) assessment model, and using the model to compare the costs and benefits of decentralised energy resources with centralised electricity supply (including network costs)

2. surveying the implementation of demand management by electricity distribution network businesses in the Australian National Electricity Market

3. surveying stakeholder perceptions of the institutional barriers to demand management and decentralised energy

4. identifying and analysing the value of monopoly network costs that are avoidable through demand management, and mapping these avoidable network costs and associated data in innovative, publicly-accessible, online ‘Network Opportunity Maps’

5. developing and applying an analytical framework for describing and understanding barriers to the efficient adoption of demand management and decentralised energy resources

6. addressing these barriers by reviewing, analysing and synthesising policy options through an innovative ‘Policy Palette’. The Policy Palette aims to support efficient investment in demand management and decentralised energy resources in the context of competitive electricity retail and generation markets and centrally planned monopoly distribution and transmission networks.

The thesis then develops a theory of ‘least cost competition’ based on five key principles: 1. Clear and appropriate purpose; 2. Public participation and accountability; 3. Cost-reflective

pricing; 4. Competition among all feasible options; and, 5. Competition based on all relevant costs.

The thesis applies these principles to the particular case of the Australian National Electricity Market. Drawing on these principles and the above research and analysis, the thesis proposes practical reforms to policy, regulation and decision-making and resource allocation processes within the electricity sector. If implemented, these reforms could lower bills and expedite the transition to a clean, low emission and affordable electricity sector, while encouraging the greater and more efficient use of demand management and decentralised energy resources.

Prologue: A Question of Balance

It is a brisk, sunny winter morning in Sydney, Australia, 1973. A 23-year-old Frenchman, as calm and cool as the weather, steps up onto a taut steel cable, secretly rigged overnight between the two northern pylons of the iconic Sydney Harbour Bridge.

He literally stops traffic, deftly walking back and forth, sitting and lying down on the narrow wire and performing tricks to the amazement of onlookers (Ricketson, n.d.). For more than an hour, Philippe Petit defies the law of the land, and the law of gravity, before stepping down (Maddox, 2008). He is arrested and fined $200. One year later, Petit will reprise his performance on an even higher stage – a cable strung between the roofs of the twin towers of the World Trade Centre in New York.

* * *

Few acrobatic stunts are as compelling and inspiring as the high wire act, with the performer protected from disaster only by an acute sense of balance. Part of the appeal is that we identify with the performer in peril. In doing so, we are perhaps reminded of the precariousness of our own lives – balanced in a delicate web of social relationships, supported by the baffling complexity of the economy and dependent on the even more intricate natural environment which sustain us.

As for the high wire walker, so too the stability of our lives, our economy and our civilisation depend on maintaining order by keeping competing forces in balance. The second law of thermodynamics reminds us that the universe, like all closed systems, tends towards greater physical and thermal disorder, or 'entropy' (Lucas, 2015). But the tendency towards disorder, though ubiquitous, is not absolute. In open systems, such as a planet externally warmed by a star, entropy can be resisted for eons, maintaining warmth, complexity and life. This occurs both literally, in physical and thermal systems, and by analogy in complex systems like ecosystems, the economy and society.

Just as Philippe Petit kept his balance, resisting the tug of gravity, our planet Earth has resisted gravity's inexorable pull to remain in a more or less stable orbit around our Sun for billions of years while life evolved. So too, the combustible chemical energy stored in fossil fuels fortuitously resisted decomposition for tens of millions of years, waiting to be tapped to drive the Industrial Revolution. Likewise in the social realm, after the turmoil of the early 20th century, effective tools of political and economic stability were developed after the Second World War, to build an unparalleled period of global economic growth.

Such economic and social stability is not accidental. It requires effective governance to maintain it. The fragility of the global economy and its dependence on the energy sector was exposed just a few months after Philippe Petit's Harbour Bridge walk. In October 1973, the OPEC oil embargo and the consequent oil price shock heralded a global recession and the end of the long post-war boom.

The following year, in 1974, the sixth special session of the United Nations General Assembly called on the World Meteorological Organisation to study the potential for human induced climate change (Zillman, 2009). This research effort culminated in October 1985, when the precarious balance of the global environment and its links to the energy sector were highlighted at a conference in Villach, Austria. The World Meteorological Organization, the UN Environment Programme and the International Council of Scientific Unions issued an unprecedented joint warning to the world that increased concentrations of greenhouse gases in the atmosphere were a grave threat to the global climate (Zillman, 2009).

* * *

Reflecting on these observations, this thesis takes the view that long-term economic stability and environmental sustainability are fundamentally linked to the stability and sustainability of the energy sector. The primary question of balance in this thesis relates to delivering an optimal balance between centralised energy supply and decentralised energy in the electricity sector. However, the thesis also recognises that such balance can only be achieved within a context of balanced energy policy. This balanced energy policy includes applying 'least cost' principles to balance demand and supply, but it also refers to balance between competition and planning in managing our electricity system, and to balancing the interests of various stakeholders.

As in the case with the high wire walker, such balance can be sustained only through vigilant effort and finely honed processes to correct imbalances promptly, lest they become catastrophic. This thesis considers how such effort and processes may be applied to the electricity sector.

Chapter 1. Introduction: Aims, Context, Approach and Method

'The market makes a good servant but a bad master'[1]

1.1 Introduction

1.1.1 An urgent challenge

This thesis is about how balance, when intelligently and equitably applied in the energy sector, can enhance human lives and sustain prosperity. It is about balancing centralised energy supply with decentralised energy resources, such as energy efficiency and load management. This thesis is also about balancing planning with competition, and balancing the role of market forces with the processes of democracy in setting the objectives and direction of energy policy.

This thesis identifies and quantifies imbalances within our current electricity system and proposes specific reforms to redress these imbalances. The focus of the thesis is on the electricity sector in Australia, but its themes have a much wider relevance.

Affordable electricity is crucial to economic prosperity. Clean electricity is crucial both to environmental sustainability and to economic prosperity. However, in recent years, the electricity sector in Australia has failed to serve either of these crucial goals. Moreover, the solutions currently proposed to address the malaise in the Australian energy sector may not succeed and could even make matters worse.

Electricity prices in Australia doubled between 2007 and 2014 (see Figure 8-5). Customer complaints and disconnection levels are at historic highs (Milmo, 2014) and courts are fining power companies for misbehaviour (Battersby, 2013). Meanwhile, Australia greenhouse gas emission, to which the electricity sector is the single biggest contributor, continue to rise (Slezak, M., 2017).

Demand management (DM) and decentralised energy (DE) offer credible solutions to the problem of how to improve the affordability and sustainability of the Australian electricity

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[1] There have been various versions of this age-old aphorism. See for example:

- *'The market makes a good servant but a bad master'* (Eckersley, 1995),
- *'The business motive is a good servant but a bad master and a society that gives itself up to the dominance of the business motive is a bad society. We do not put first things first in putting ourselves first*,' Lord Beveridge, 1948 (cited in: Tony Cutler et al., 2013, p.38)
- *'markets … make a good servant but a bad master, and a worse religion'* (Hawken et al., 1999, p.261)
- *'Money is a good servant, but a bad master'* Sir Francis Bacon (1561–1626)

sector. Yet for over forty years, these solutions have been persistently neglected and rejected by policy makers. Why is this so? Why have efforts to create a cleaner and more affordable electricity system failed? What have been the consequences? What is the likely outcome if this pattern continues? What can be done to remedy this parlous situation?

This thesis aims to answer these questions.

1.1.2 Genesis of this thesis

It is customary in a PhD thesis for the author to reflect on how they came to the research.

An earlier working title for this was: 'The Good Servant' – reflecting the adage that 'the market is a good servant but a poor master'. This thesis argues for a better balance between the roles of market, planning and public participation in managing the electricity system. In this sense, the thesis is critical of the role that economic neoliberalism has played in steering the electricity system towards outcomes that are neither competitive nor efficient.

This is not to say that the problems in the Australian electricity system stem from too much competition. On the contrary, this thesis argues that competition has been too limited and too focussed on the supply side to the exclusion of the demand side of the market. More importantly, the thesis also argues that electricity market has been insufficiently guided by the public interest. The productive role of competition and market will only be fulfilled if the public interest is paramount, and if these competitive processes are balanced with other tools and approaches where appropriate.

While good research may seldom be driven by disinterested curiosity alone, it must always be accompanied by a deep commitment to be guided by the evidence. I did not approach my research with disinterested curiosity about the potential for decentralised energy (DE) to lower electricity bills. On the contrary, during thirty years of observation of and participation in the energy policy debate in Australia, I became dismayed at the evident waste of resources and the associated adverse economic, environmental and social impacts associated with the development of the electricity sector. These range from economically unjustified hydro-electric dams, to the construction of numerous power lines of dubious merit, to the dominant role of coal-fired power stations in Australia's and the world's greenhouse gas emissions.

My first active engagement with the electricity sector was in the campaign to save the Franklin River from the Gordon-below-Franklin Dam in 1982/83. I formed the view that the impetus to build the proposed dam was driven, not by the public interest or a sound business case, but by institutional factors reflecting vested interests and political conventions. This experience was a key driver for me to study economics and policy development and the uses and abuses to which they are put.

After completing a bachelor's and a master's degree in economics and political economy and after 15 years' experience working in electricity utilities, regulatory authorities, government departments and industry associations, my views about the shortcomings of the prevailing decision-making processes within the electricity sector were strengthened. It was on this basis that I decided to undertake this doctoral research.

1.2 Aims and research questions

The overall aims of this doctoral study are:

1. to assess the potential to enhance economic efficiency and environmental sustainability by applying the principles of least cost planning in the competitive electricity industry
2. to propose practical reforms to decision-making and resource allocation processes within the electricity sector to encourage more efficient use of demand management and decentralised energy resources
3. to do this with a particular focus on the Australian National Electricity Market.

In pursuit of these aims, I address the following **two key research questions**:

1. To what extent could greater use of demand management in the electricity sector lead to both lower costs and lower greenhouse gas emissions?
2. How could changes to the way that electricity networks are regulated, managed and developed lead to more efficient use of demand management?

I address these research questions by:

1. surveying the implementation of demand management by distribution network businesses in the Australian National Electricity Market
2. comparing costs and benefits of decentralised energy resources with the costs and benefits of centralised electricity supply, including network costs

3. analysing the value of network costs that could be avoided through demand management
4. developing and applying an analytical framework for describing and understanding barriers to the efficient adoption of demand management and decentralised energy resources
5. reviewing, analysing and synthesising policy options to address these barriers to support efficient investment in demand management and decentralised energy resources in the context of competitive electricity retail and generation markets and centrally planned monopoly distribution and transmission networks.

1.3 Context and key concepts

1.3.1 The limits of centralised power

The electricity sector in Australia, as around the world, is in the midst of a fundamental transition from a system based on large centralised coal- and gas-fired power stations towards a smarter, cleaner, more decentralised system.

Barely a decade ago, centralised electricity generation Australian was forecast to increase by more than 60%, from 252 TWh in 2004–05 to 408 TWh in 2029–30 (Cuevas-Cubria, 2006). The Energy Supply Association of Australia (ESAA) estimated that to meet electricity load growth over this period, between $35 billion and $78 billion in capital expenditure would be required to build 30,000 MW of new generation facilities. The ESAA estimated that an *additional* $35 billion investment would also be required to upgrade existing facilities and networks over the same period (Energy Supply Association of Australia, 2007). However, that future has disappeared. In the eleven years since these forecasts were made, the outlook has changed so much that, as shown in Figure 1-1, demand for centralised electricity supply (indicated by the dotted lines) is now not expected to exceed 2007 levels at any time before 2035.

More striking still is the fact that this transition has occurred in a period of continuous economic growth. Economic growth has been accommodated, and is expected to continue to be accommodated, not by increased centralised electricity generation, but by growth in decentralised energy resources, including end-use energy efficiency and rooftop solar photovoltaics (PV).

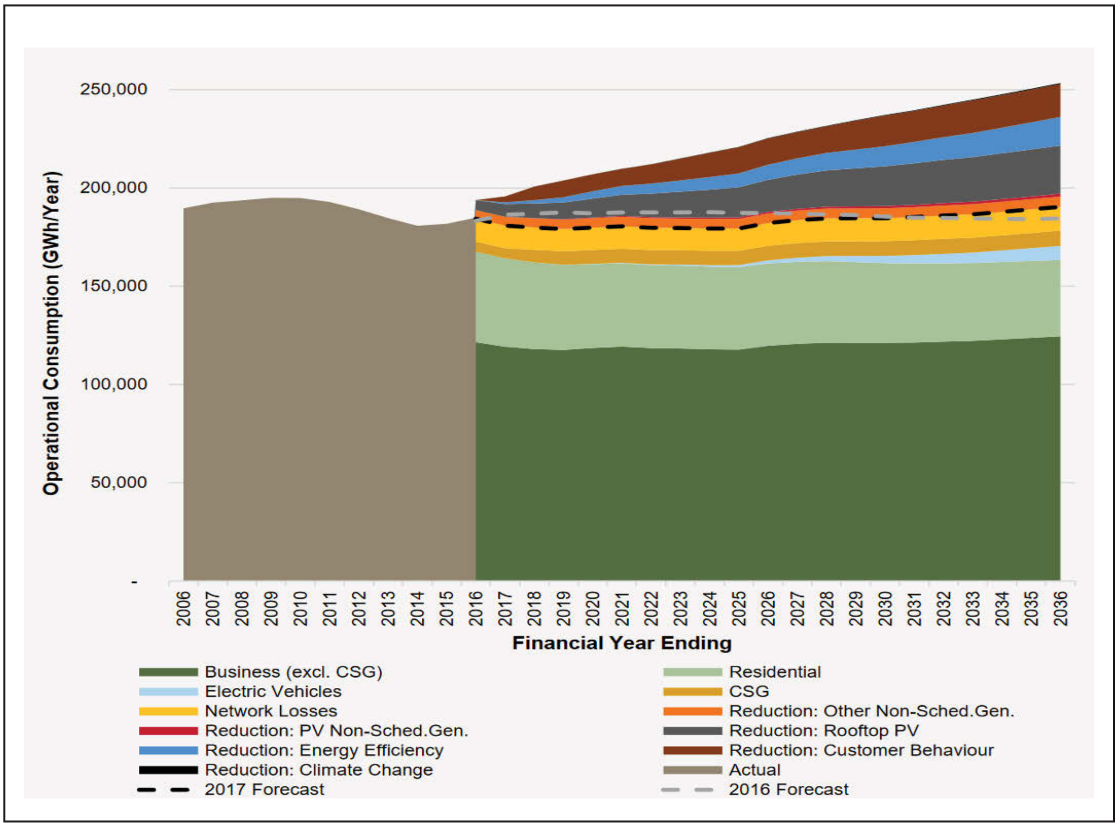


Figure 1-1 Annual electricity consumption forecast for the National Electricity Market (AEMO, National Electricity Forecasting Review, July 2017)

As illustrated in Figure 1-2, the Australian Government's 2004 Energy White Paper indicated that the past trends of rapid increases in energy demand were expected to continue, and the vast majority of this growth in demand was expected to be met by coal, oil and natural gas (Australian Government, 2004). By contrast, the 2015 Energy White paper did not even include energy consumption projections.

With decentralised energy already meeting all the growth in demand for energy services in the electricity sector, it may seem there is little need for a stronger effort to expand DE and demand management. But the contrary is true for two reasons. Firstly, the existing fleet of coal- and gas-fired power stations are aging and most will need to be replaced over the next two decades. Indeed, ten coal-fired power stations have closed in Australia in the past six years (Dunstan et al., 2017, p. 8). Secondly, most new generation that is expected to be built over the next decade or more will be variable output solar and wind power stations. This variablity of output needs to be complemented with flexible resources. The least costly such flexible resources are demand-side resources: flexible pricing, behaviour change, demand response and energy efficiency.

It is important to note that the greater penetration of renewables will require active demand management not just to reduce load when the “net load” (that is, load minus renewables) is too high, but also when net load is “too low”, that is when renewables are generating more than the required load. DE and DM will have crucial role both in shifting load to take advantage of this “surplus” generation from time to time, and also in ensuring that we do not build more renewable energy capacity than necessary.

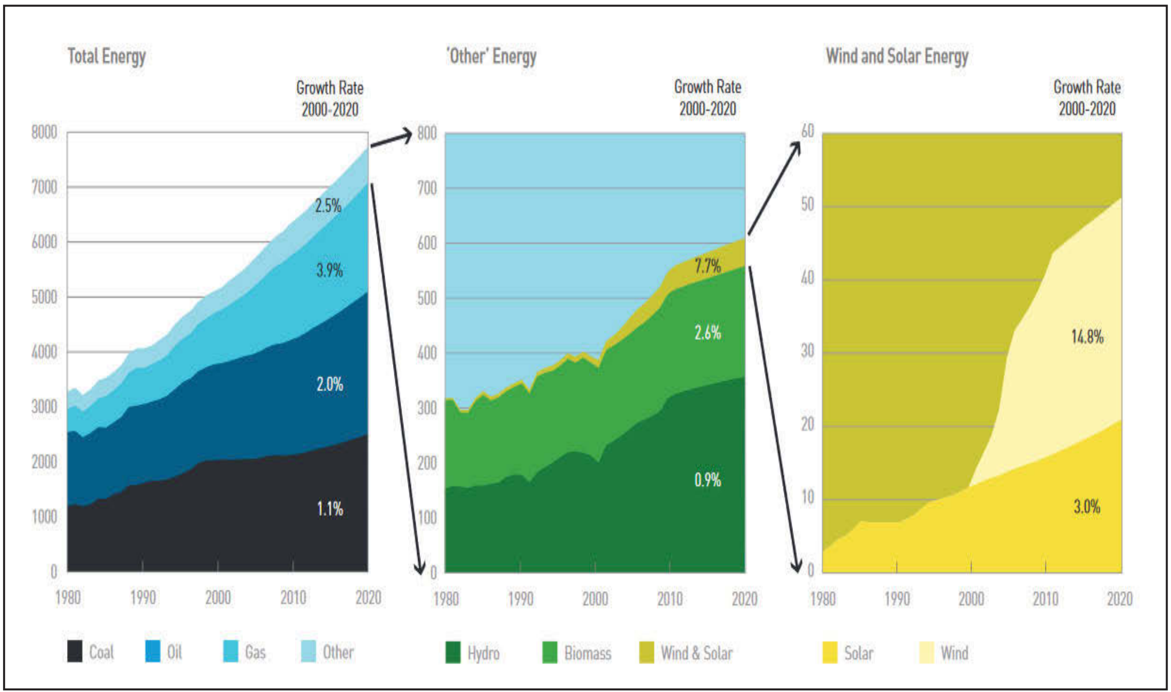


Figure 1-2 Composition of Australian energy supply

(Australian Government, 2004)

But while electricity consumption growth has largely disappeared in Australia in the past decade, electricity consumption growth overseas is still significant. The implications of this continued growth in fossil fuel use is illustrated in Figure 1-4, with emission growth projections based on current trends likely to lead to an increase in average global temperatures of more than three degrees by the year 2100. Such a temperature increase is more than the level that the Stern Review indicated would be economically worse than the combined impact of both world wars and the Great Depression (Stern, 2006).

Electricity and sustainable development

Probably the greatest long-term challenge facing the electricity sector is climate change, as the electricity supply industry is the biggest source of global greenhouse gas emissions both globally and in Australia.

As illustrated in Figure 1-3 below, the largest portion of these global greenhouse gas emissions, and the fastest growing source of emissions, is energy supply and in particular, electricity generation. So, any serious attempt to reduce greenhouse gas emissions must address the electricity supply industry and the factors that are driving the continued growth of its emissions.

In recent years, concern about the global challenge of climate change has increased to the point where it now rivals or even eclipses the dominant issues in the electricity supply industry of affordability, competition and industry structure. Given the prominence and interconnectedness of the two issues of market structure and climate change, any engagement with either one must also address the other.

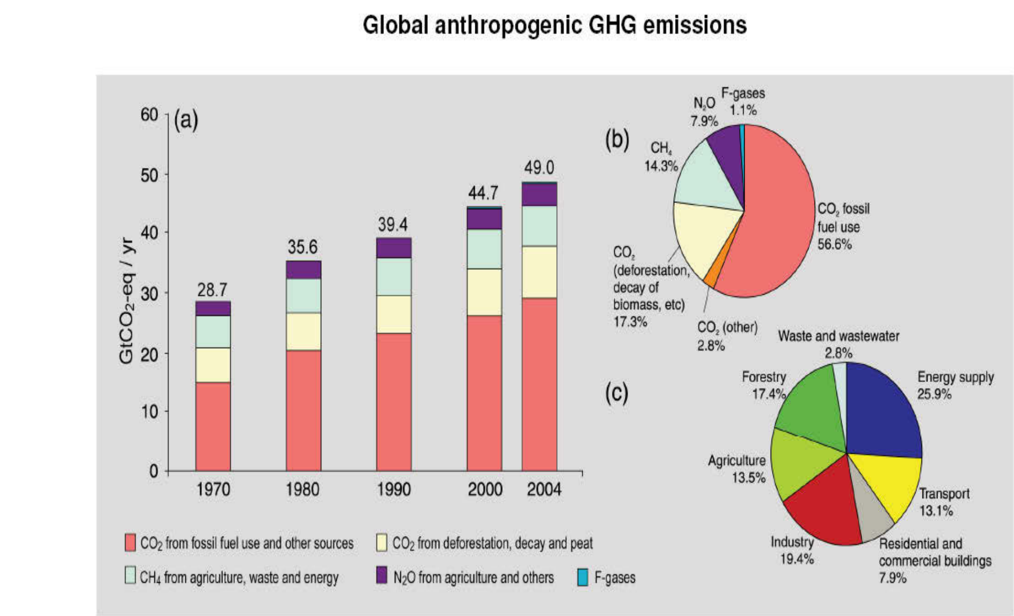


Figure SPM.3. (a) Global annual emissions of anthropogenic GHGs from 1970 to 2004.[5] (b) Share of different anthropogenic GHGs in total emissions in 2004 in terms of CO_2-eq. (c) Share of different sectors in total anthropogenic GHG emissions in 2004 in terms of CO_2-eq. (Forestry includes deforestation). {Figure 2.1}

Figure 1-3 Global greenhouse gas emissions

(UNFCCC, 2007)

What are the alternatives?

According to the common definition of sustainable development as development which meets 'the needs of the present without compromising the ability of future generations to meet their own needs', the current direction of energy policy is unsustainable (World Commission on Environment and Development, 1987, p.8). The balance of scientific evidence indicates that our current global energy production and consumption trends place us on a collision course with the global climate system (IPCC 2007, Hansen 2007).

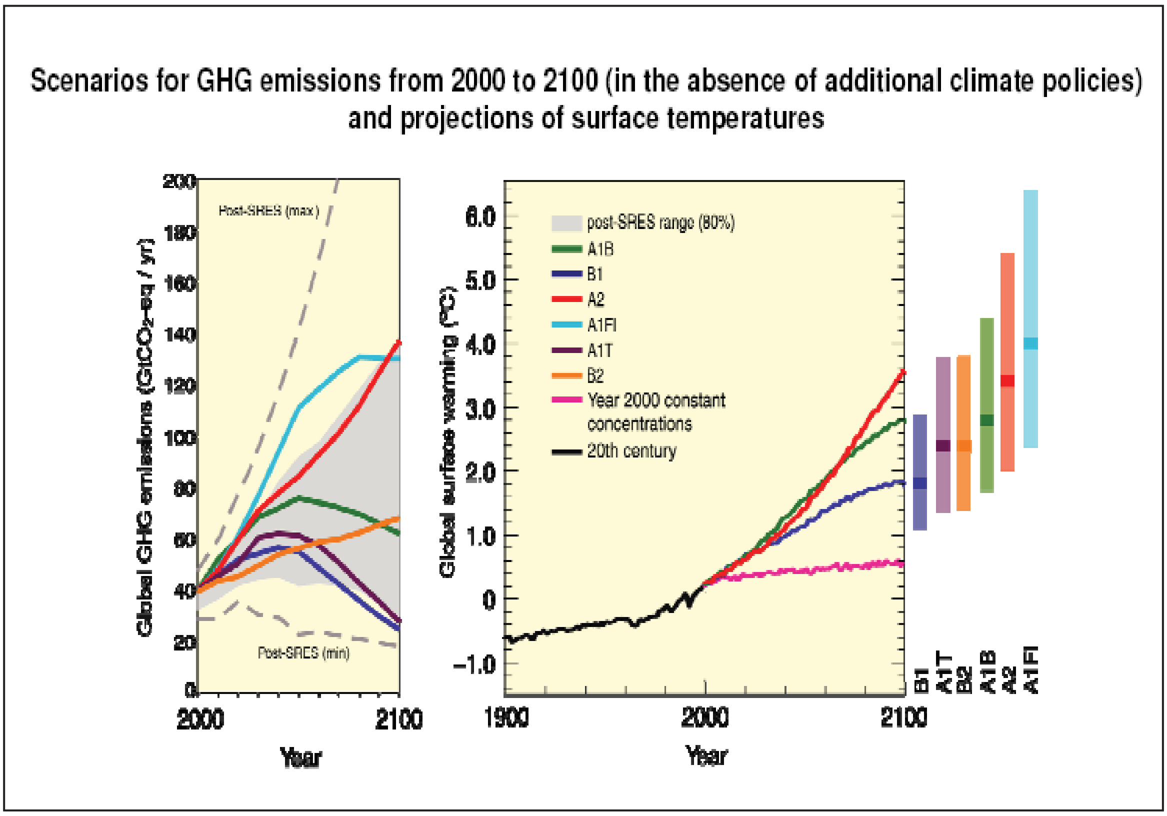


Figure 1-4 Global greenhouse gas emission scenarios
(IPCC, 2007)

However, trend does not equal destiny, and there is an array of solutions available to avoid such a collision. As the IPCC noted,

> There is high agreement and much evidence that all stabilisation levels assessed can be achieved by deployment of a portfolio of technologies that are either currently available or expected to be commercialised in coming decades, assuming appropriate and effective incentives are in place for their development, acquisition, deployment and diffusion and addressing related barriers (Intergovernmental Panel on Climate Change, 2007).

Sustainable energy paths have been strongly advocated for more than four decades. For example, in 1976, Amory Lovins wrote:

> [There are] two energy paths that the United States might follow over the next 50 years … The first path resembles present federal policy and is essentially an extrapolation of the recent past. It relies on rapid expansion of centralized high

> technologies to increase supplies of energy, especially in the form of electricity. The second path combines a prompt and serious commitment to efficient use of energy, rapid development of renewable energy sources matched in scale and in energy quality to end-use needs, and special transitional fossil-fuel technologies. This path, a whole greater than the sum of its parts, diverges radically from incremental past practices to pursue long-term goals (Lovins, 1976).

The largest share of low-cost abatement in the energy sector resides in **decentralised energy**– that is, energy efficiency, peak load management and distributed generation.

There is a rich literature on alternative energy futures for both the global and Australian contexts (e.g. Stern 2006; International Energy Agency 2006; CSIRO 2006; Business Leaders Roundtable 2006). One of the most influential works in this literature is the 'Socolow wedges' analysis, which identifies fifteen technological emission abatement options, each capable of reducing global carbon emissions by 1 gigatonne per annum by 2054. As illustrated in Figure 1-5 and Figure 1-6, this analysis indicates that the equivalent of seven of these options would need to be enacted quickly in order to put the planet on a path to stabilising concentrations of atmospheric greenhouse gases at less than double the pre-industrial carbon dioxide levels (500 ppm) (Socolow 2004).

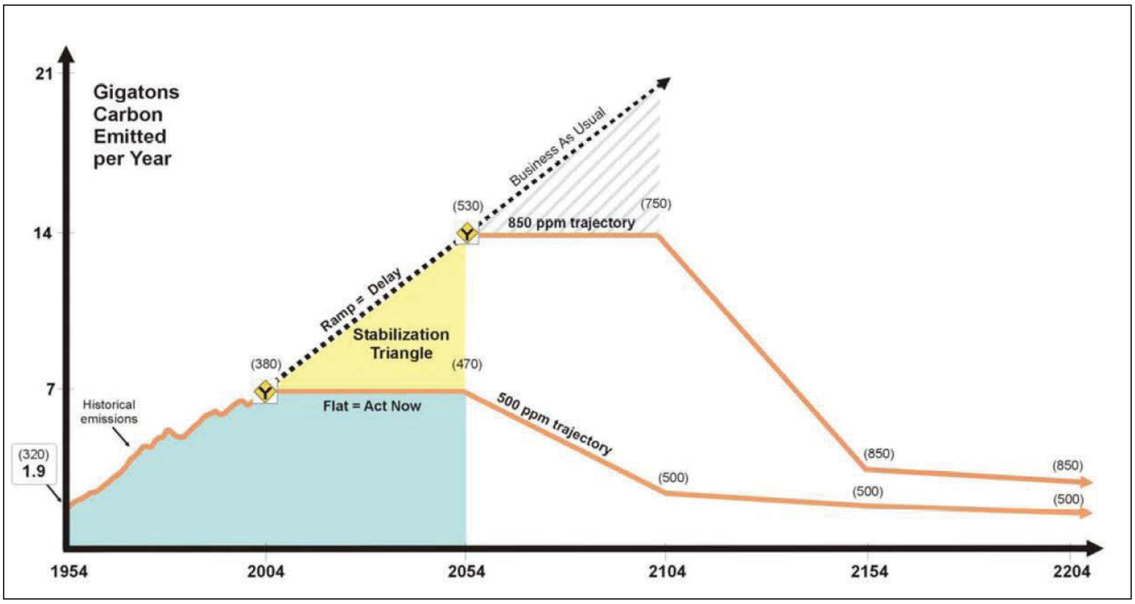


Figure 1-5 Greenhouse gas emission scenarios
(Socolow, 2004)

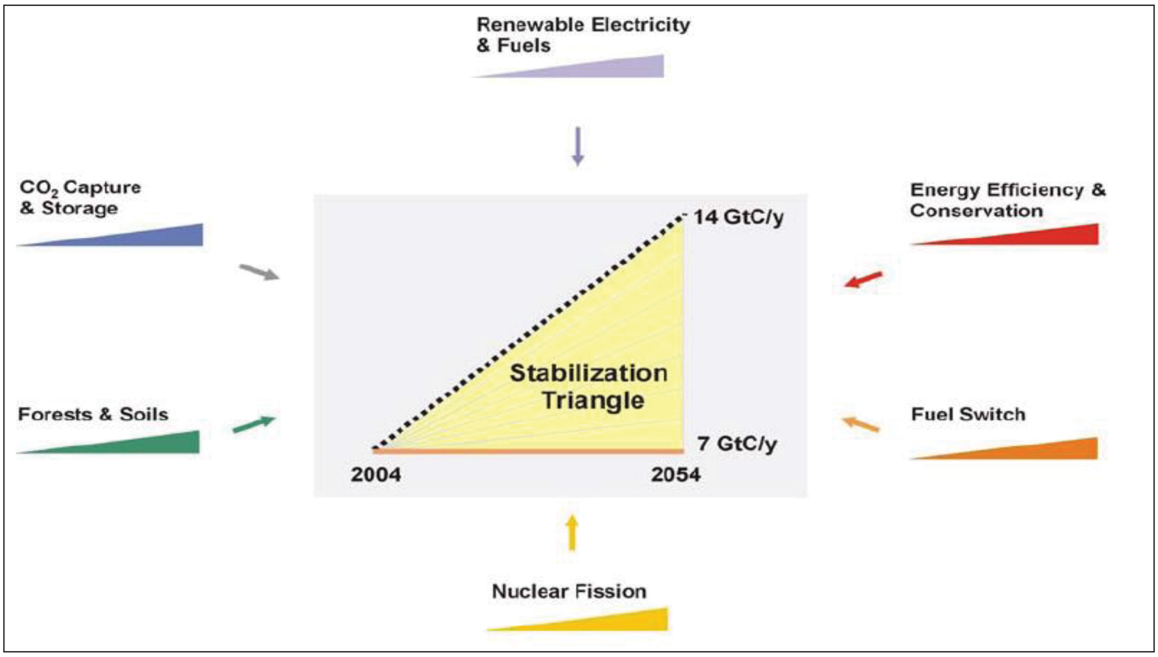


Figure 1-6 Stabilisation wedges

(Socolow, 2004)

The consulting firm McKinsey and Company built on this analysis by compiling a list of global emission abatement options in the form of 'a cost curve for greenhouse gas reduction'. McKinsey and Company estimated that there is potential to reduce global emissions by 26 gigatonnes of carbon dioxide equivalent per annum, or 45% below business as usual, by 2030 at a marginal cost of 40 euros per tonne of carbon dioxide (Enkvist et al., 2007). McKinsey and Company have since published a more detailed analysis for the United States, which (as illustrated in Figure 2-6) found that,

> The United States could reduce greenhouse gas emissions in 2030 by 3.0 to 4.5 gigatons of CO2e [31% to 46%] using tested approaches and high potential emerging technologies. These reductions would involve pursuing a wide array of abatement options available at a marginal cost less than $50 per ton, with the average net cost to the economy being far lower if the nation can capture sizable gains from energy efficiency (McKinsey and Company, 2007).

1.3.2 The rise of decentralised energy

In recent decades, the previous trend towards larger scale and greater centralisation in the information technology and telecommunications industries has reversed. Today the dominant industry players are not the big infrastructure owners, but the providers of distributed, and often mobile, services to millions of consumers; companies such as Facebook, Apple, Netflix and Google.

Likewise, the energy industry is now moving from a traditionally highly centralised structure to a more decentralised one. This transition is being driven by technological change, customer preferences and environmental pressures. This trend has been described as the biggest change in the sector since widespread electrification began.

The rapid rise of 'decentralised energy', including rooftop solar PV, local generation, demand response, energy-efficient equipment and smart controls, and soon, battery storage and electric vehicles, has the potential to cut carbon emissions, reduce costs and improve service reliability and security. However, achieving these objectives simultaneously requires well-designed and targeted policy measures.

> In the context of this thesis, **'decentralised energy' means electricity generation and management of energy use applied at or near the point of energy use**. Decentralised energy includes distributed generation, load management (including energy storage) and energy efficiency technologies and practices, as illustrated in Figure 1-7.

It is noted that this is a relatively broad definition of 'decentralised energy'. The terms 'decentralised energy' and 'distributed energy' have different meanings in different contexts. For example, in many instances, these terms are used narrowly to refer to local small-scale generation, for example, 'energy that is generated off the main grid' (Andrews Tipper) and 'any resource on the distribution system that produces electricity and is not otherwise included in the formal … Bulk Electric System' (North American Electric Reliability Corporation, p. 1)

Others adopt broader definitions of decentralised energy , such as, '[Distributed energy resources] are physical and virtual assets that are deployed across the distribution grid, typically close to load, and usually behind the meter, which can be used individually or in aggregate to provide value to the grid, individual customers, or both … such as solar, storage, energy efficiency, and demand management' (Deora et al.) and 'Distributed Energy … encompasses a diverse array of generation, storage and energy monitoring and control solutions' (Arup and Siemens).

Decentralised energy is generally located closer to consumers than centralised sources. For example, decentralised energy can involve heating, cooling and powering a commercial building using a combination of solar panels, fuel cells, energy efficiency and load control. Examples of decentralised energy resources are illustrated in Figure 1-7.

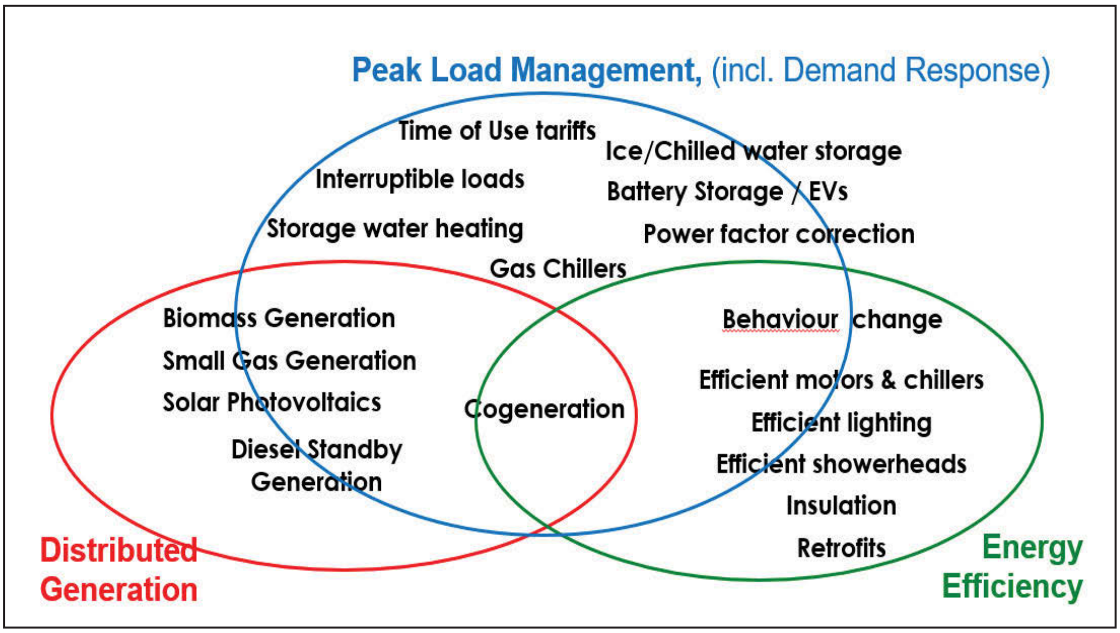


Figure 1-7 Decentralised energy resources

(Adapted from IPART 2002, p. 102)

'Distributed generation' is one form of decentralised energy and refers to smaller scale generation technologies and can include: solar panels, micro turbines, fuel cells cogeneration (also known as 'combined heat and power') and smaller wind turbines (but not those connected to the high voltage transmission network)

Energy efficiency, or to be precise, increased efficiency in the use of energy, is generally the lowest cost form of decentralised energy and the form with the greatest potential to reduce energy related carbon dioxide emissions. Recognising the potential economic and environmental benefits of energy efficiency, the European Union has issued an Energy End-use Efficiency and Energy Services Directive and adopted a target of improving end use energy efficiency by 20% by the year 2020 (Commission of the European Communities, 2005 and 2006).

Peak load management is probably the form of decentralised energy with the greatest capacity to reduce the need for new electricity infrastructure and the most cost effective means for complementing variable renewable energy generation, like wind and solar power.

Figure 1-8 provides a useful summary of DE technologies and their potential capabilities.

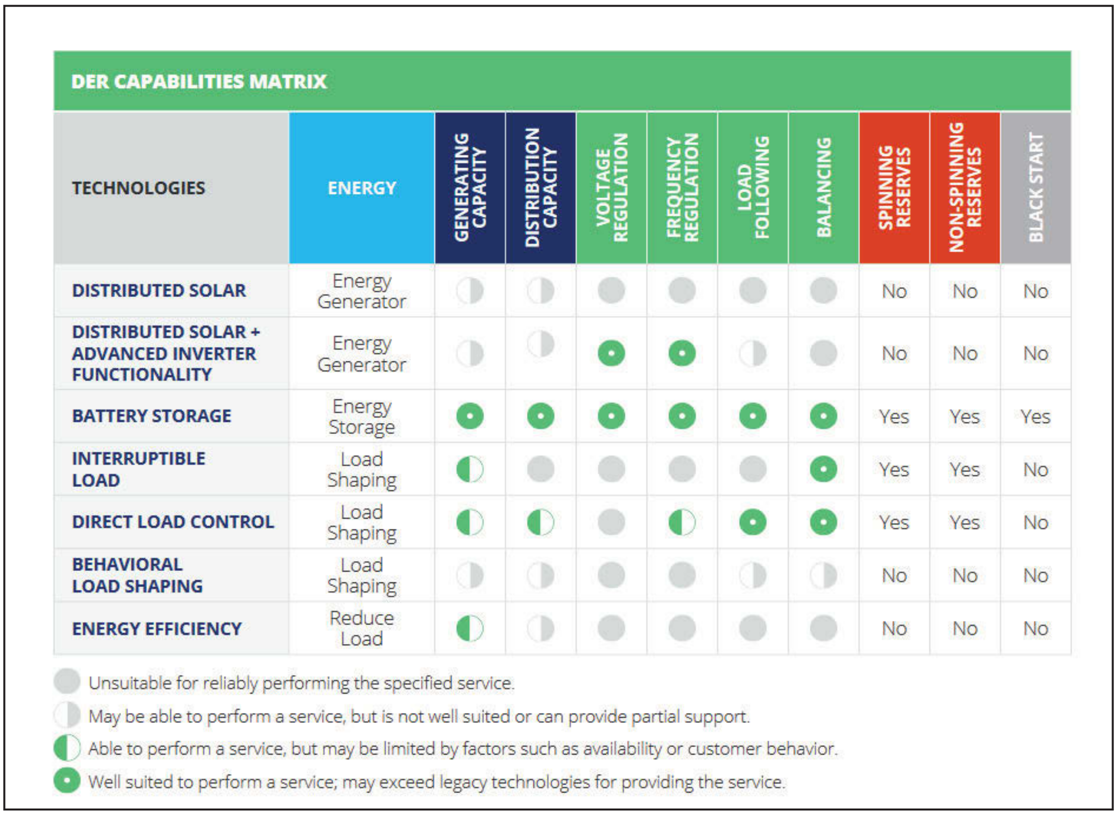


Figure 1-8 Decentralised energy resources capabilities matrix

(US Smart Electric Power Alliance)

A key driver in the rise of decentralised energy has been pressure to reduce costs to consumers. This pressure is particularly strong in Australia where electricity prices doubled between 2007 and 2014 (see Figure 8-5).

To minimise energy bills, electricity utilities in general, and network businesses in particular, should be incentivised to procure a least cost mix of supply side and demand side options, including energy efficiency, peak load management and distributed generation and storage solutions. However, to do this requires accessible, reliable, detailed information about where such resources should be deployed and what they are worth.

Numerous studies have concluded that many decentralised energy resources, and in particular energy efficiency initiatives, are not just low cost but negative cost. In other words, the value of the energy savings that result from these measures exceeds the cost of implementing them. For example, the Australian Government's *Energy White Paper* (2004) estimated the net benefits of energy efficiency could amount to a $975 million increase in national economic output, while measures to encourage the uptake of demand management could deliver a boost to of $630 million to economic output (see Figure 1-9).

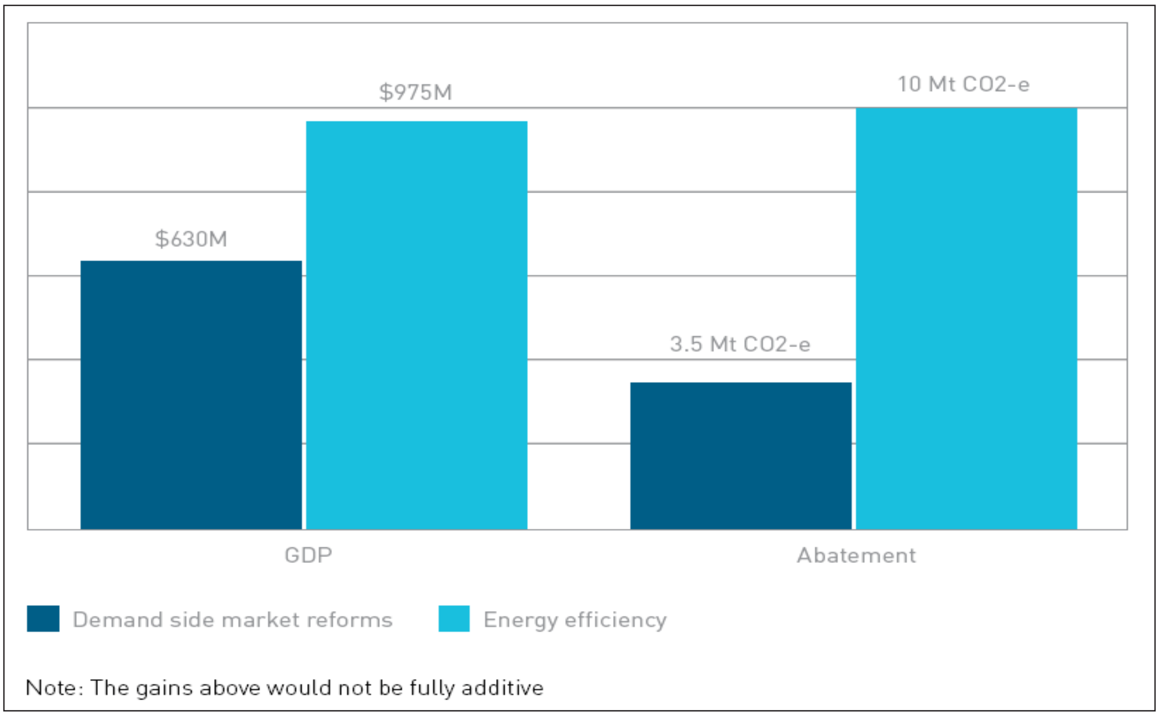


Figure 1-9 Estimated benefits of demand management and energy efficiency in Australia (Australian Government, 2004).

The relative cost of individual decentralised energy resources is illustrated in Figure 2-6 and discussed in detail in Chapter 2.

1.3.3 Competition and centralised planning in electricity markets

This thesis assesses the practicality and potential benefits of applying 'market-based' least cost planning in Australia's electricity industry. At a practical level, this thesis addresses the research questions outlined in Section 1.2 above. At a theoretical level, the thesis analyses the philosophical and conceptual foundations on which fundamental market structure policy decisions are made. At this level, the key research question is about balance – how to find the right balance between the roles of market competition and of centralised planning in the electricity sector, particularly in the current context of an urgent need to reduce greenhouse gas emissions. The thesis explores this question of balance by addressing the following related questions:

- How should society reconcile economic growth and affordable electricity with environmental protection and reducing greenhouse gas emissions?

- How should society choose between building new power stations and network infrastructure, and supporting decentralised energy resources?

The role of the market has been contentious in the supply of electricity, virtually since Thomas Edison patented his light bulb in 1880. Formal electricity regulatory agencies were established in most states of the USA in the early 20th century (Troesken, 1992) and since then there have been movements from state control towards competitive markets and vice versa on a regular basis. The focus of electricity policy reform over the past two decades, particularly in Australia, has been on a greater role for competitive markets (see for example: Industry Commission 1991; Australian Government 2002; Productivity Commission 2005).

The tension between market competition and centralised planning has arguably been the dominant issue in economic policy for over a century. This tension was a key element of the Cold War and was often perceived as a defining element in the tussle between capitalism and communism (Hayek 1944). From an ideological perspective, it can be tempting to see these two approaches to resource allocation as incompatible polar opposites. However, in practice, complex human societies have always solved resource allocation problems by combining elements of both market competition and centralised planning.

Even in the most 'free market' economies, centralised planning (and monopoly supply) constituted the dominant market structure of the electricity supply industry in the 100 years after the development of the first public electricity supplies in the 1880s. However, since the electricity market reforms of the UK in late 1980s and early 1990s, governments in many countries, including Australia, have strongly advocated competitive market structures and increasingly have adopted them. This question of whether to adopt competitive markets or central planning has dominated electricity policy debates across the world over the past three decades. The ongoing debate over electricity reform and privatisation, and sometimes renationalisation, highlights the currency of these issues in Australia.

The success of competitive electricity markets has been patchy (Joskow 2006). While employment in the electricity industry has generally decreased and labour productivity has increased, price reductions (beyond historical trend) have tended to be concentrated among the larger business consumers (Beder 2003; Hodge 2004). Meanwhile, peak demand, overall electricity consumption and associated greenhouse gas pollution have increased dramatically over most of this period.

There are also mounting concerns about the adequacy of maintenance expenditure and investment in new generation and network capacity. These concerns have been highlighted by a series of major electricity blackouts and crises in, for example, Auckland in February 1998 (Ministry of Commerce of New Zealand 1998), California in 2001 (Borenstein 2002), the north-eastern states of the US in 2003 (New York Independent System Operator 2005), and London and Italy in 2003.

Despite these concerns, the development of more competitive electricity markets continues apace in Australia with full retail competition now applying in all five NEM states and the ACT, and NSW has followed Victoria and South Australia in removing retail safety net tariffs (AEMC and KPMG, 2014; Ministerial Council on Energy, 2007).

Rather than focus on the relative merits of competitive markets and central planning, my research considers the potential to draw judiciously on the elements of both approaches. In particular, I ask whether *the way* that we apply competition in parts of the electricity industry (e.g. parts of generation and retail), and regulation and centralised planning in others (e.g. transmission and distribution networks) is appropriately balancing customer preferences relating to cost and customer service with community preferences relating to fairness and environmental impact.

1.3.4 Least cost planning and demand management

Least cost planning (LCP) has been described as:

> …guidelines to encourage electric utilities to meet their customers' needs for adequate, reliable and efficient energy services at the lowest total cost while remaining financially sound. To achieve this goal, utilities should plan to meet future loads through timely acquisition of an integrated set of demand- and supply-side resources. Importantly, this includes actively pursuing and acquiring all cost-effective energy conservation. The cost effectiveness of all resources should be determined with respect to long-term societal costs (Harrington, 2006).

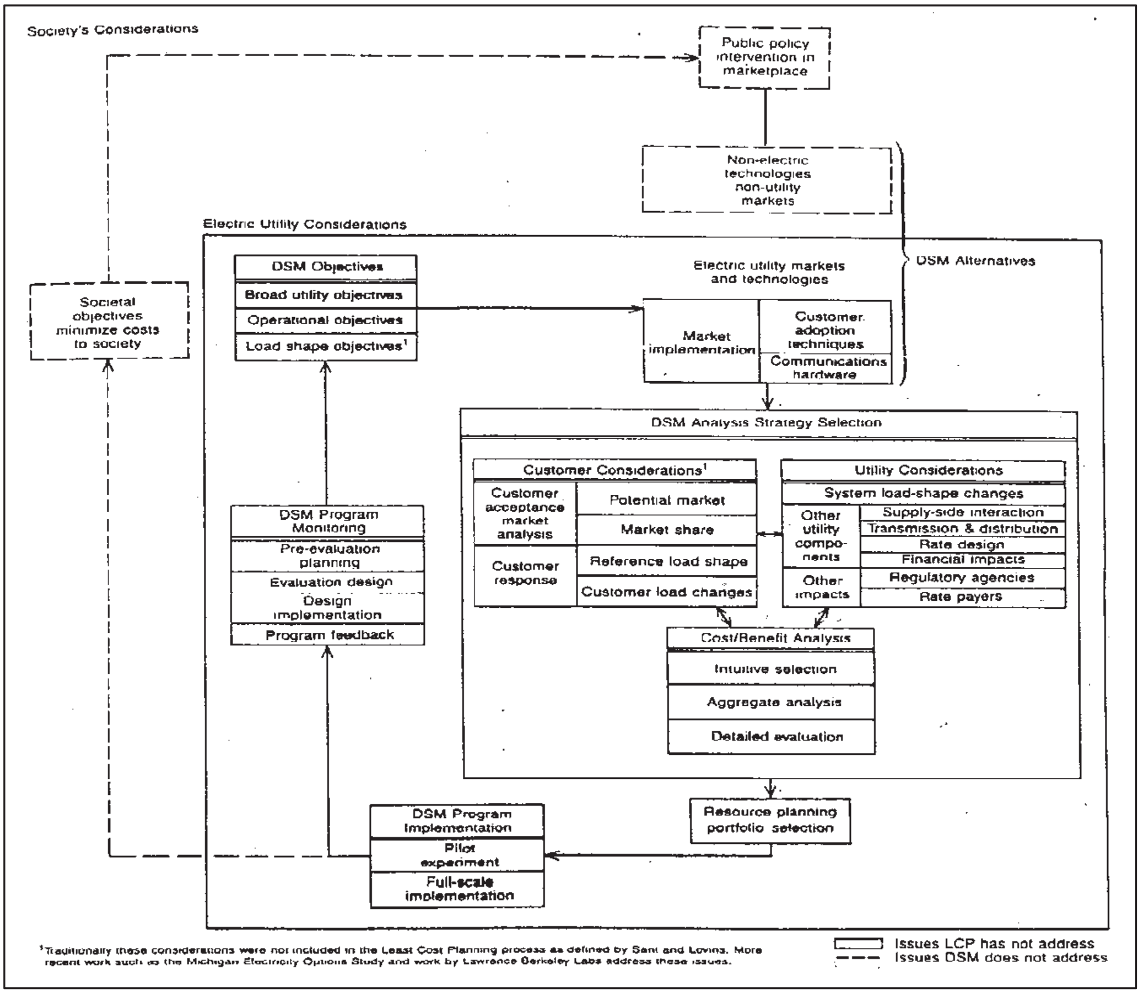


Figure 1-10 Least cost planning framework
(Gellings & Chamberlin, 1993a)

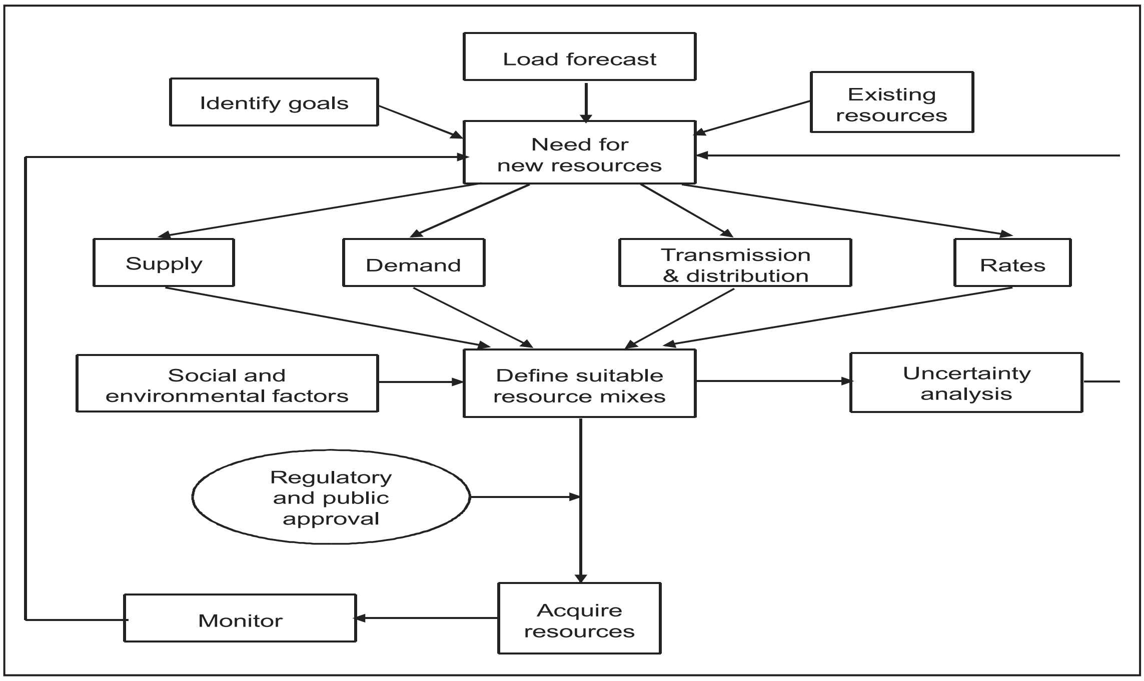


Figure 1-11 Least cost utility planning process
(Electrical World, 1989)

LCP is essentially a planning process that seeks to achieve an optimal balance of demand-side and supply-side options to meet given objectives. In the electricity context, these objectives typically include ensuring that the energy service needs of a particular community are met. The objectives of LCP may also include environmental goals, such as reducing greenhouse gas emissions. As illustrated in Figure 1-10, and more simply in Figure 1-11, LCP is based on a framework of economic efficiency and benefit-cost analysis. The lowest-cost mix of options that meets the given objectives is 'the best'. As the name suggests, LCP is a form of centralised planning. With the recent emphasis on relying on competitive markets to make resource allocation decisions in the electricity generation and retailing sectors, the role of LCP has been neglected in Australia and overseas (Swisher et al. 1997).

A key element of LCP is the capacity to compare 'demand-side' and 'supply-side' options. Electricity demand-side options (or 'decentralised energy resources') include energy technologies that are applied on the customer side, or 'demand side', of the electricity meter. They include end use energy efficiency, load management and distributed generation and energy storage. LCP was developed in the 1970s and 1980s, largely in response to evidence that electricity supply utilities were failing to take advantage of these demand side resources. This was so even when demand side options appeared to be significantly more cost-effective than traditional supply-side options, such as building new centralised power stations and augmenting power networks.

While the application of traditional LCP may at first glance appear incompatible with competitive electricity markets, this thesis assesses the potential value of applying the principles of LCP in the context of competitive electricity markets.

As David Mills notes, demand side management (DSM) was originally defined as:

> …the planning and implementation of those utility activities designed to influence customer use of electricity in ways that will produce desired changes in the utility's load shape - i.e., in the time pattern and magnitude of a utility's load. Utility programs falling under the umbrella of demand-side management include load management, new uses, strategic conservation, electrification, customer generation, and adjustments in market share. (Electric Power Research Institute, 1984).

The US Energy Information Administration adopted a broader definition in 1997 (Energy Information Administration, p. 1, emphasis added):

> Demand-Side Management (DSM) consists of electric utilities' planning, implementing, and monitoring of activities designed to encourage consumers to modify their levels and patterns of electricity consumption ... Utilities implement DSM programs to achieve two basic objectives: **energy efficiency and load management.** Energy efficiency is primarily achieved through programs that reduce overall energy consumption of specific end-use devices and systems by promoting high-efficiency equipment and building design ... Load management programs, on the other hand, are designed to achieve load reductions; primarily implemented at the time of peak load. Load reduction programs have little effect on total energy consumption.

As Mills points out,

> Australian utilities have maintained the original definition of DSM, focusing predominantly on the notion of load management. The most common DSM practice in Australia involves the promotion of off-peak hot water systems. The use of off-peak hot water systems leads to reduced demands for more generating plant (reduced peak load), but produces an increase in overall electricity consumption (reduced energy efficiency). Such actions present a stark contrast with the more widely held notions of DSM (as practiced in the US) where the concept of DSM is generally associated with improvements in energy efficiency (Mills, 1997).

For the purposes of this thesis, I have adopted a simpler definition:

> Electricity demand management (DM) means deliberate action by those responsible for electricity supply to reduce or shift demand for electricity, as an alternative to providing supply to meet that demand.

Based on this definition, DM *does not include* supply interruption or involuntary load shedding (i.e. 'blackouts'), or independent decisions by consumers to lower their demand or energy use.

1.3.5 From least cost planning to least cost competition

A key focus of this thesis is on what can be learned from least cost planning and applied to the competitive electricity market to improve its efficiency and deliver better outcomes for consumers and the community. The structure of the Australia's competitive National Electricity Market (NEM), is summarised in Figure 1-12. As shown, significant parts of the system are not competitive at all, but are managed via centrally planned or "administered" processes. The network sector is the most prominent of these.

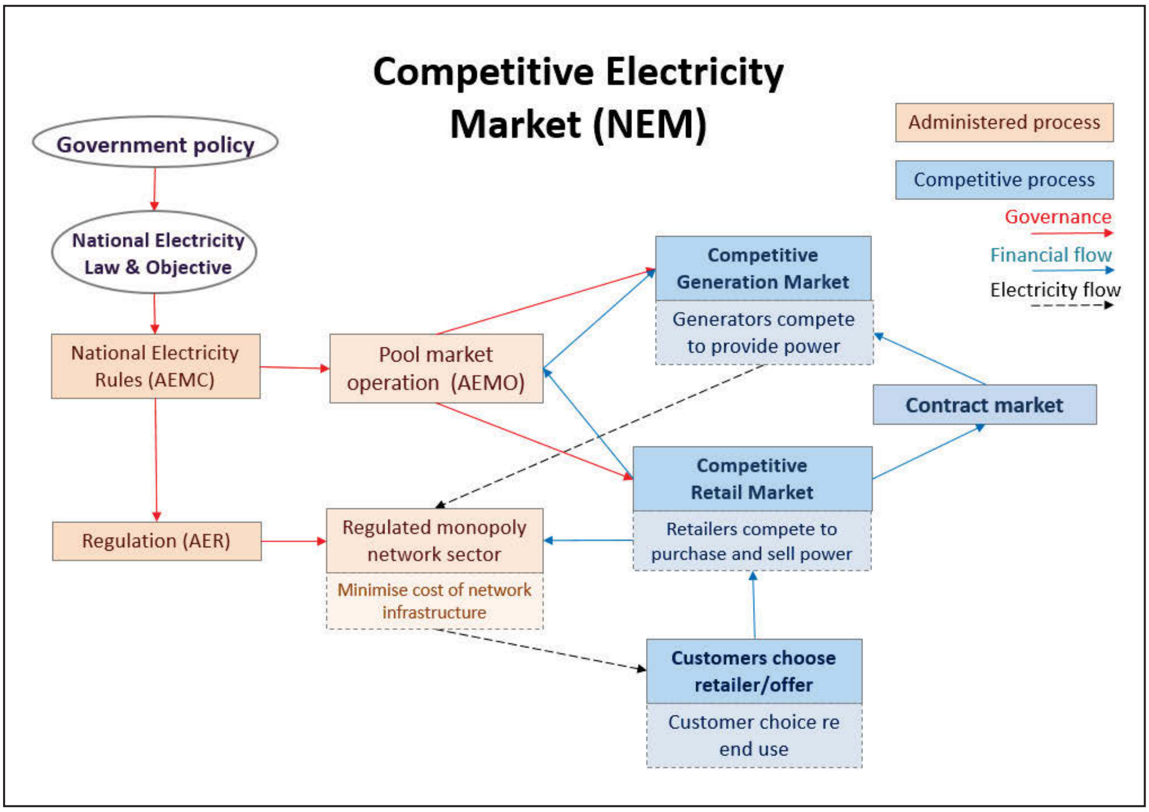


Figure 1-12 Competitive market process

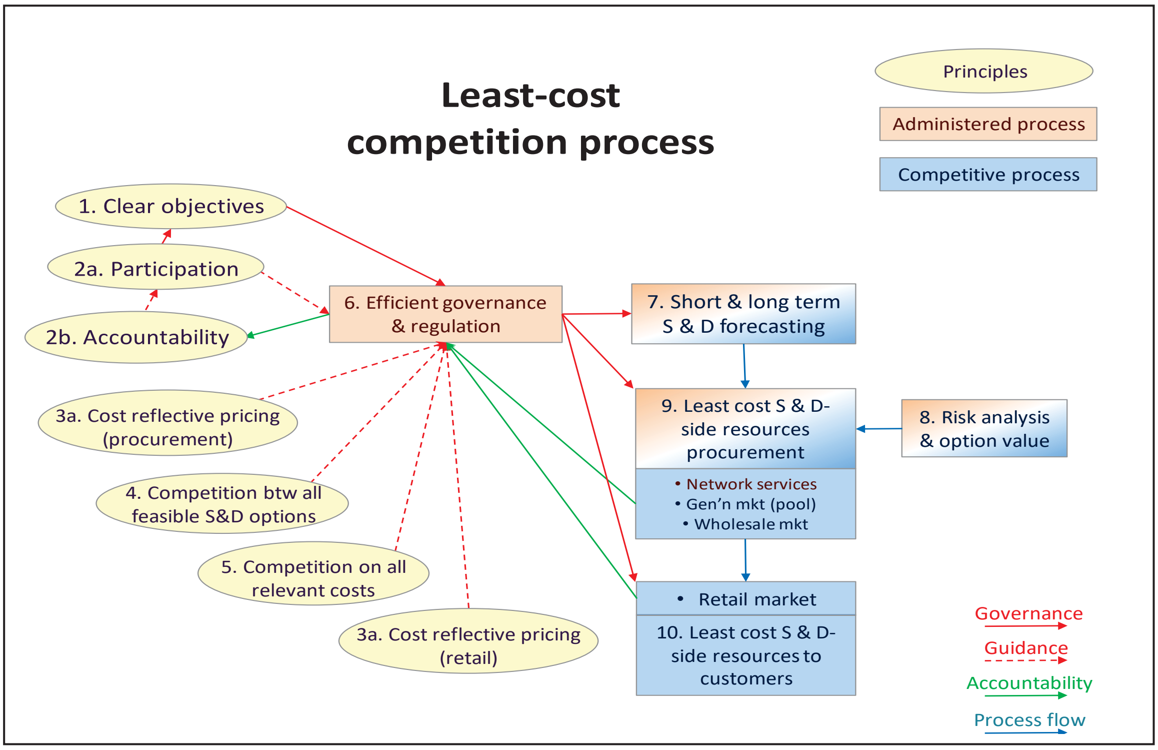


Figure 1-13 Generic least cost competition process

Least cost planning cannot be directly applied to the NEM as “planning” is not compatible with the competitive elements of the market. However, there are many principles of least cost planning that are applicable to the NEM. Chapter 7 of this thesis examines these opportunities in detail to develop five principles of “least cost competition” for a more efficient and customer focussed electricity system. These principles are shown in Figure 1-13, in which outlines a generic least cost competition process. As it derives from the principles of least cost planning, least cost competition is focused on how to achieve an appropriate balance of supply and demand options at least cost. Chapter 8 discusses how this generic process could be applied to the Australian NEM.

1.4 Methodological approach

My methodological approach to this research can be described in terms of Crotty’s four elements of research (Crotty, 2003).

Firstly, the ***epistemological stance*** I am adopting is essentially a “social constructivist” one. This does not mean that I do not believe in an objective reality separate from its social and cultural attributes. Indeed, much of the focus of analysis relates to the physical and financial attributes of various energy technologies that can be determined by reference to engineering specifications and market prices. Rather, the social constructivist stance is a reflection of the complexity of the interactions between human beings in relation to both the choice of technology and the creation of processes for assessing and selecting technologies. In other words, while the range of technological choices is ultimately bounded by objective physical limits, my view is that the range of choices within these limits is so wide, that the key issues to be addressed in this research relate to matters that are strongly influenced by social and cultural factors.

Secondly, my ***theoretical perspective*** is broadly based in institutional economics. So while much of my analysis is largely based on questions of efficiency and value, these questions are informed by a framework that recognises that the economy is best understood, not as approximations of deterministic perfect competition, but rather as being capable of delivering a wide range of outcomes depending on how institutions apply their influence. Elements of this ‘imperfect competition’ include: market and political power; imperfect information;

significant transaction costs; consumer preferences that may be influenced by institutions, advertising, fashions and social mores; firms that are motivated by factors other than

maximising profit; and the significant roles played by governments (Galbraith, 1967). Furthermore, I adopt a normative approach in that the functioning of the economy cannot be usefully conceived of purely in efficiency terms, but must also incorporate social, political and ethical dimensions.

Thirdly, reflecting a transdisciplinary approach, I employ a range of ***research methodologies*** as appropriate to different elements of my research. These include the following:

Least-cost planning (LCP) – analysing the relative costs of decentralised and centralised energy.

Soft system methodology (SSM) – to analyse the barriers to adopting decentralised energy, and to develop strategies to address these barriers. Given that the complexity of the 'problem situation' includes both 'hard' (technical) and 'soft' (human) dimensions, a soft systems approach seems well suited to understanding and interpreting it (Checkland, 1981). The process of developing 'rich pictures' is also seems a good fit, given my use of visual tools in the DANCE, D-CODE and policy mapping models for improving the process. On the other hand, a drawback of using this methodology is that the openness of SSM conflicts with the predefined direction of my research in relation to the proposed models. Furthermore, the relatively formalised structure of SSM in relation to the construction of 'root definitions' (via the 'CATWOE' classification) did not integrate well with other elements of my methodology. Consequently, I have not formally applied SSM, but I have drawn on elements of it and other soft system approaches such as Everett Rogers' Diffusion of Innovation Theory (Rogers, 1962) and Donella Meadows' System Dynamics (Meadows et al., 1972).

Given my parallel involvement in the CSIRO Intelligent Grid Research Cluster (2007-2011), which involved 'hands on' industry engagement in exploring options to develop decentralised energy, it also draws on some principles of action research (Lewin, 1946) such as some of John Heron's ideas relating to the collaborative and iterative process of cooperative inquiry (Heron, J. 1996). I also build on the theory of market transformation by drawing on the work of Blumstein and Coakley (Blumstein et al. 2000, Coakley and Hoffman, 2002). This also involves integrating the principles of micro-economic theory in conceptualising the role of transaction costs as a barrier to the efficient uptake of decentralised energy.

Fourthly, I use a range of research methods and tools, including:

- A critical review of the primary and secondary literature including scholarly journals, policy documents and ‘grey’ literature from industry and regulatory sources.
- Surveys of the level of demand management activity undertaken by electricity distribution network businesses in Australia. These are used to assess the extent of support for decentralised energy resources and the application of LCP principles.
- Mathematical modelling of decentralised energy technologies. Data was drawn from a range of sources including published data, unpublished data and input data from other models where available, and industry sources. This modelling was mainly undertaken in a detailed spreadsheet in Microsoft Excel.
- Microeconomic marginal cost analysis to define avoided network costs. Data for this was drawn from Distribution Annual Planning Reviews (DAPRs, formerly known as Annual Electricity System Development Reviews in some states). In some cases, additional data was sought directly from the network businesses.
- Geographical information systems were used to produce static and dynamic maps of network constraint costs and decentralised energy opportunities.

The role of the modelling in the research

The purpose of the D-CODE and DANCE models (described below) in the thesis is to provide a framework for analysis of different energy demand- and supply-side options in the context of LCP. The two models are intended to incorporate a number of key innovations. More importantly, however, the models are used as tools to assess the potential benefits and costs of decentralised energy resources, and to analyse the potential practicality and desirability of applying the principles of LCP in the context of competitive electricity markets.

As indicated in numerous references, such tasks as these have been undertaken before in various ways. This thesis attempts to ‘stand on the shoulders of giants’ in drawing on, elaborating and synthesising the insights and work of predecessors while also integrating their insights with my own original contributions.

1.5 Thesis outline

The structure of my thesis is summarised in Figure 1-14 and discussed in detail below.

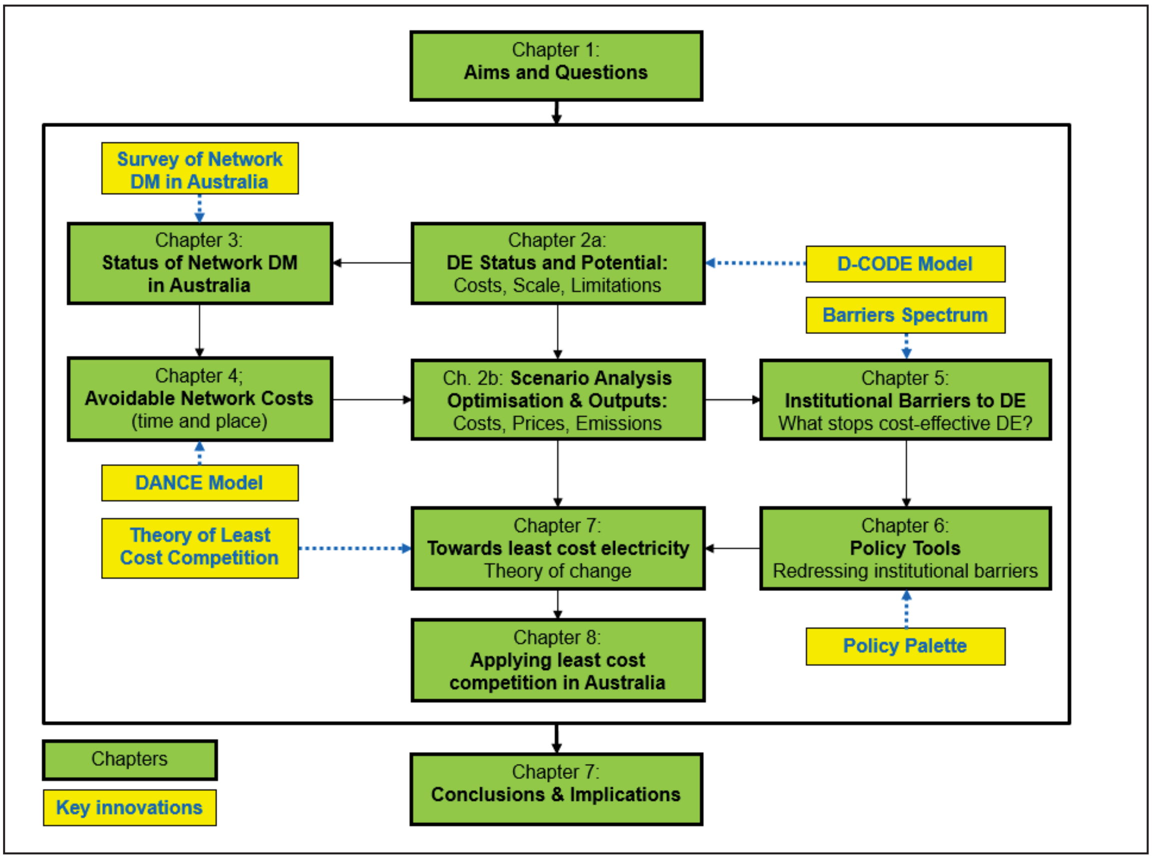


Figure 1-14 Thesis structure, including chapters and key innovations

1.5.1 Analysing the potential for decentralised energy

For decentralised energy to fulfil its potential, it is essential that all relevant benefits and costs are identified, understood and evaluated. For example, one key advantage of decentralised energy technologies that is often underestimated, in both economic evaluations and regulatory processes, is that they meet energy needs at or near the point of use, and thereby reduce the need for electricity network infrastructure. On the other hand, electricity network operators and consumers often have concerns about the impact that decentralised energy technology may have on their capacity to manage the network and supply reliability.

Chapter 2 outlines a rigorous, transparent and innovative framework for a balanced approach to evaluating and comparing decentralised energy technologies with each other and with centralised supply alternatives. This part of the thesis reviews and describes the full range of economic, environmental and social benefits that can be attributed to decentralised energy resources.

This framework, the Description and Cost of Decentralised Energy (D-CODE) model aims to transcend simple benefit–cost analysis of different decentralised energy technologies by providing an accessible tool that allows energy specialists, policy makers and interested laypeople to conduct their own analyses. The model incorporates all key parameters needed to allow the costs of the technologies to be compared.

The D-CODE model is designed to be applicable nationally and to any state or jurisdiction. It includes the option of either inputting new values or selecting in-built default values based on generic average values or values relevant to a particular state or region.

The D-CODE model is innovative in combining the following features:

- It is fully transparent, free and accessible.
- It is generic and adaptable.
- It is comprehensive:
- It is scalable:
- It can incorporate the avoided benefit and cost data from other parts of this thesis including the DANCE model (see Section 1.5.2), and where quantifiable, the other identified benefits.

The D-CODE model is applied to assess the potential efficiency benefits available from greater use of decentralised energy resources in the Australian electricity industry.

1.5.2 Analysing avoidable network costs

Unprecedented levels of investment in monopoly electricity networks have been approved by regulators in NSW and Queensland, as illustrated in Figure 1-15 (Independent Pricing and Regulatory Tribunal of NSW 2004; Queensland Competition Authority 2005; Independent Pricing and Regulatory Tribunal of NSW 2006; Queensland Competition Authority 2007). Over the 2009–14 period, these network businesses were approved to spend $45 billion on capital expenditure, equivalent to about two-thirds of their total current asset value at that time.

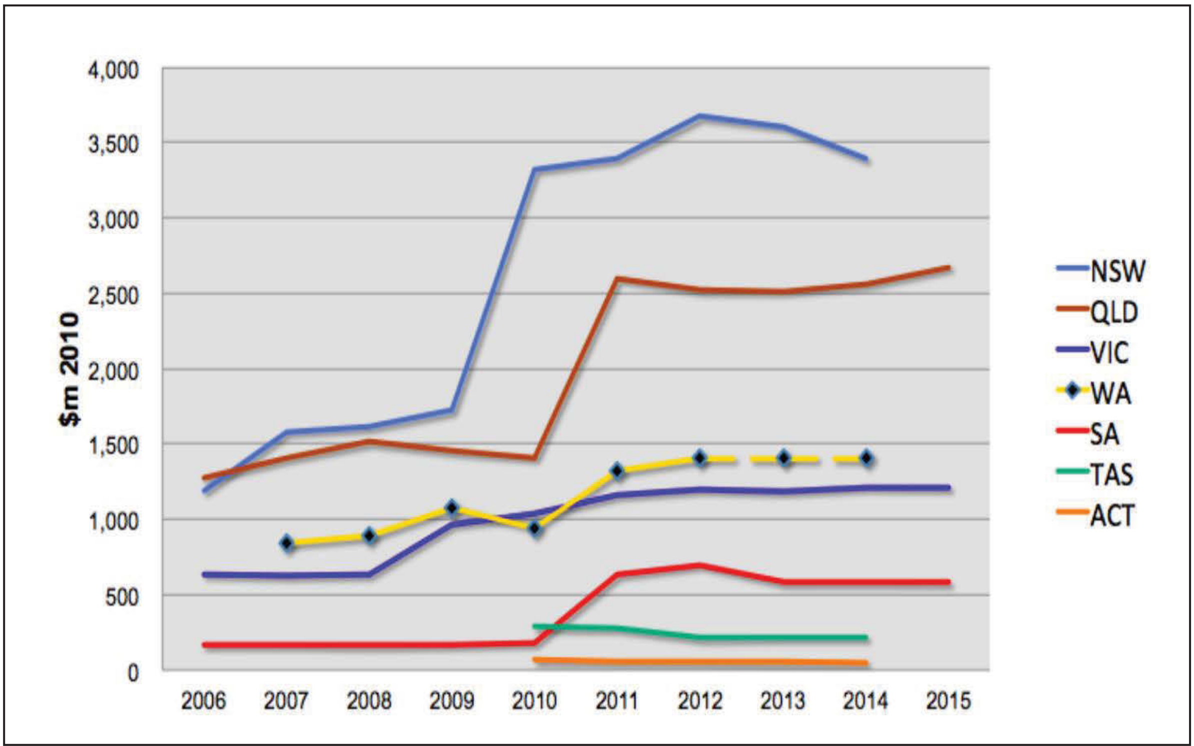


Figure 1-15 Electricity network capital expenditure (T&D) by jurisdiction, 2006–2015 (Langham et al., 2011a, p.1)

As a consequence of this unprecedented investment in network infrastructure, electricity network charges increased rapidly, eroding the productivity gains in the generation and retail sectors. This investment was driven by forecasts of ever-increasing energy consumption and was associated with projections of significantly increasing greenhouse gas emissions.

This capital expenditure raised considerable debate in Australia about the potential for decentralised energy resources to reduce network investment requirements (IPART 2002, Energy Futures Australia 2002, Pareto and Associates 2004, East Cape 2002, Sinclair Knight Merz 2003).

In the past, the absence of data about network constraints, costs and potentially avoidable investment has been a major obstacle to the development of energy efficiency, local generation and storage, and peak demand management projects. Consequently, these decentralised energy resources have not been optimally deployed in relation to network capacity and constraints. This has contributed to over-investment in network infrastructure and to the doubling of electricity prices in Australia.

The key focus of Chapter 4 is on the potential to extend the competitive process to the development of networks. Avoiding or deferring the need for network infrastructure augmentation is probably the single biggest source of value for decentralised energy resources. A recent innovation which can tap this value is to use information disclosure, cost-reflective prices and market incentives. This approach was pioneered by the NSW Demand Management Code of Practice for Electricity Distributors (DEUS 2004)[2]. This approach has allowed avoidable network costs (and therefore the network-related benefits of decentralised energy resources) to be mapped (Dunstan, 2007).

Research for this thesis takes this approach further to analyse dynamic avoidable costs not just on an annual $/MW per year basis, but to a full marginal cost allocation in $/MWh on an hour-by-hour basis across a network.

The model developed a robust dynamic cost allocation method and applied this method to the entire National Electricity Market over a ten-year forecast period. The model presents this data in a series of user-friendly online 'Network Opportunity Maps'. (See http://www.energynetworks.com.au/network-opportunity-maps.)

The Dynamic Avoidable Network Cost Evaluation (DANCE) model offers, for the first time, a detailed, transparent and robust framework for accurate real-time network cost analysis, and for estimating the aggregated hour by hour benefits offered by decentralised energy within a constrained grid.

This approach also provides a sound basis for estimating the potential economic efficiency gain that could be achieved through the greater deployment of decentralised energy. Given that in Australia network investment far exceeds generation investment, network efficiency gains are likely to provide the largest source of benefits to support the expansion of decentralised energy. For example, in NSW alone, planned capital expenditure on distribution and transmission infrastructure regularly exceeded $3 billion per annum (see Figure 1-15).

1.5.3 Analysing barriers to decentralised energy

The long history of studies indicating the low or negative costs associated with more sustainable decentralised energy resources raises the question: Why are all these opportunities not being taken up? The conventional answer to this question is that there are a range of barriers which obstruct the optimal adoption of DE resources.

[2] I played a key role in this process, as a lead author in drafting the code, when working for the NSW Department of Energy, Utilities and Sustainability.

Chapter 5 examines the technical, financial, cultural and regulatory barriers that obstruct the full recognition of the above benefits. These barriers have been widely discussed over many years (see for example Greene, 1991). A major review into demand management by the NSW Independent Pricing and Regulatory Tribunal in 2002 listed the following barriers (IPART, 2002):

- market inertia
- lack of information
- first cost bias
- exclusion of external environmental costs
- structure of planning processes
- perverse regulatory incentives
- lack of available expertise /experience
- higher perceived risk
- distorted price signals
- market rules and regulations
- transaction costs
- the relatively low cost of electricity.

This thesis extends this analyses of barriers by using a novel and more systematic categorisation of barriers to the adoption of decentralised energy resources. Determining the energy supply and consumption mix is not simply a process of the consumer deciding what energy-using equipment to buy and how much to use it. Rather, it depends on a complex chain of decisions made by numerous agents in both the supply of energy and the supply of energy-using equipment (including buildings and appliances) as illustrated in Figure 1-16.

Each of these decision-making agents has to weigh up, not just the purchase and running costs of each item, but also a range of other factors, as illustrated in Figure 1-17. In this context, it is neither surprising nor 'irrational' that many cost-effective opportunities to invest in decentralised energy are not taken up. This is consistent with the precepts of bounded rationality theory which recognises that life is often too complex to allow perfectly efficient or optimal decisions at all times, and that other decision-making processes, 'rules of thumb' or 'heuristics' are often substituted for pure rationality (Simon 1991).

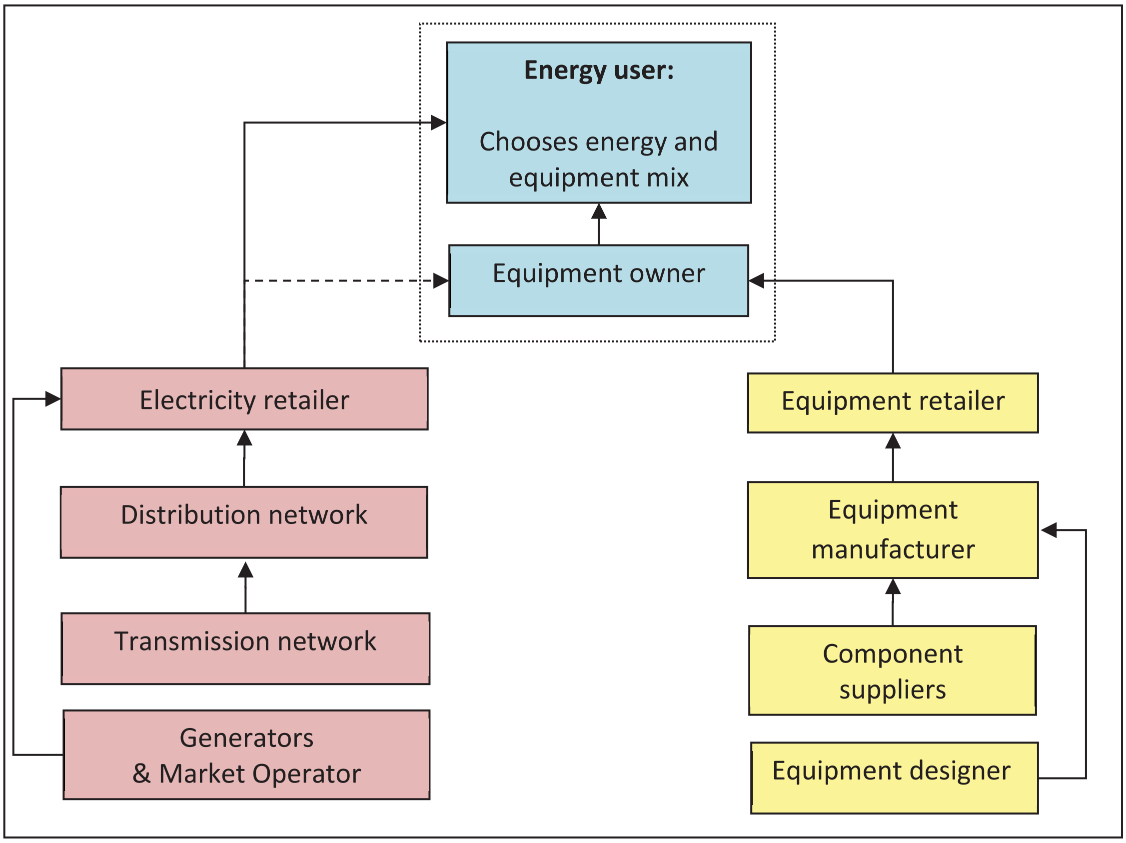


Figure 1-16 Energy decision path – the scope for cascading inefficiencies

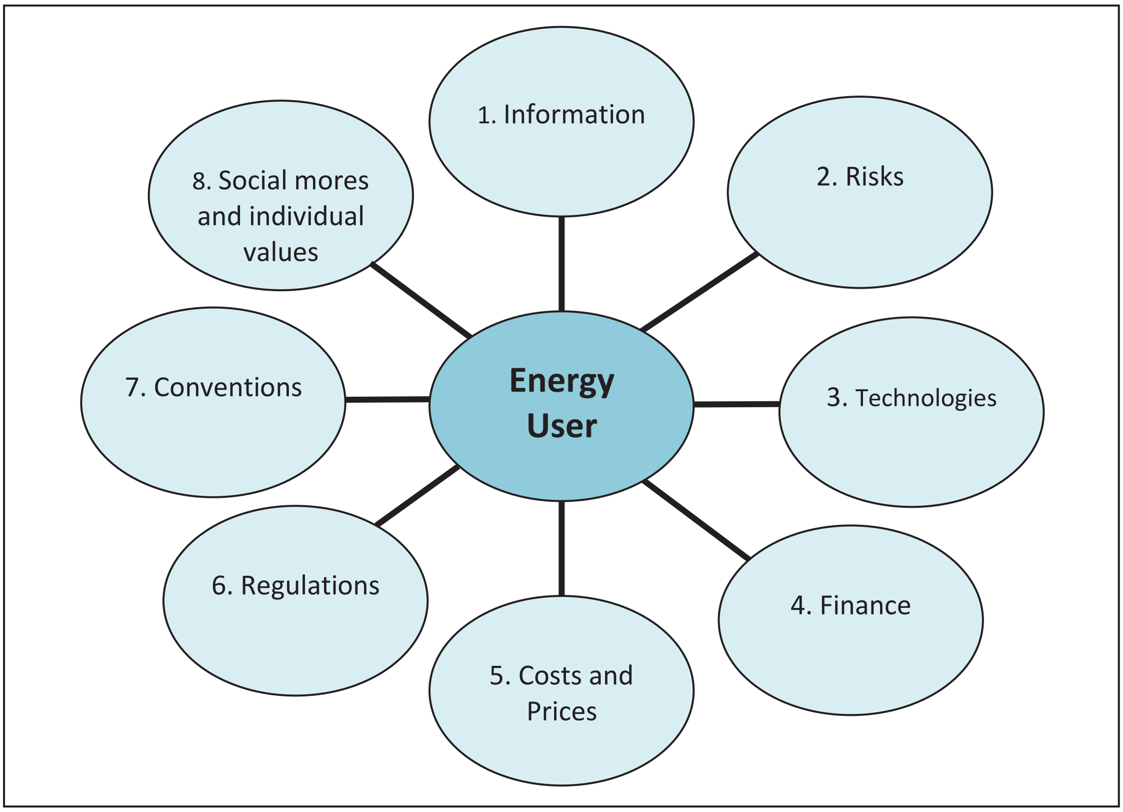


Figure 1-17 Factors influencing decisions about energy use

However, the mere existence of a rational basis for inefficient behaviour does not mean that it cannot be changed. For each of the above barriers there are possible solutions. Wherever the benefits of reducing the inefficiency exceed the cost of applying a solution, there is a prima facie case for applying the solution.

Economic regulatory barriers to decentralised energy resources

Chapter 5 examines economic regulatory barriers to decentralised energy development and mechanisms to overcome them. In particular, where regulatory structures link network businesses' profits directly to electricity throughput and/or do not allow network businesses to retain financial savings associated with adopting cost-effective decentralised energy resources, there will be little incentive for electricity network businesses to commit to the development of such options.

Perverse regulatory incentives represent one particularly important barrier to the development of decentralised energy resources because of their strong influence and their amenability to policy reform. Where economic regulatory structures penalise network businesses that invest in prudent, decentralised energy resources, it is highly unlikely that these businesses will facilitate use of such resources (Harrington et al., 2006).

Chapter 5 also considers major possible barriers in the current development of the Australian electricity market that could be addressed. These include:

1. the segregation of generation investment decision-making from network planning
2. the conflation of the generation short-term dispatch (kWh) market with the long-term generation capacity investment market
3. the disconnect between retail customers and generation market price signals
4. the absence of effective time-based and location-based price signals for electricity networks
5. the exclusion of external costs (especially in relation to greenhouse gas emissions) from prices
6. the neglect of the capacity for decentralised energy resources (including end-use energy efficiency) to offer lower cost options.

1.5.4 The 'Policy Palette': policy tools to address barriers DM and DE

Whereas Chapter 5 analyses the barriers to the more efficient use of decentralised energy resources, Chapter 6 examines policy measures to overcome these barriers and encourage consumers and utilities to adopt decentralised energy resources and thereby capture efficiency opportunities. In particular, Chapter 6 focuses on the theory and practice of market transformation, including a novel classification of policy instruments in the form of a 'Policy Palette'.

Market support vs. market transformation

The potential gains from decentralised energy resources will only be realised if the costs associated with adopting these policy measures are less than the value of the efficiency gains that will be obtained from applying them.

Offering 'market support' through subsidies can of course encourage the adoption of decentralised energy resources. However, if this not strategically targeted at reducing barriers then it may have little long-term effect and may even add additional barriers and inefficiencies of its own. 'Market transformation' has been defined as: 'a strategic effort by a utility and other organization to intervene in the market, causing beneficial, lasting changes in the structure or function of the market, leading to increases in the adoption of energy-efficient products, services and / or practices' (Schlegal et al. 1997).

Market transformation is informed by the view that markets are shaped as much by conscious and unconscious social factors as by technical factors, and are therefore amenable to a range of deliberate strategies for change.

Figure 1-18 illustrates this concept in terms of the orthodox economic supply and demand analysis. The quantity of a given commodity such as a decentralised energy option that is being used in the economy is initially at level q_0, at price p_0, reflecting the cost of supply and the level of effective demand. To increase the uptake of this commodity, there are essentially three possible courses of action:

a) Lower the cost of supply (i.e. move the supply curve to the right, from S_0 to S_1).
b) Increase the demand for the commodity (i.e. move the demand curve to the right, from D_0 to D_1).

c) Reduce the transaction costs which are currently supressing the effective demand below the true demand. (This could be represented as either a lowering of the supply curve or as a lift in the demand curve.)

The same principles are illustrated in a simpler form in Figure 1-19, in the form of ‘pushing’ the market through mandatory measures such as regulation, ‘pulling’ the market through incentives such as rebates or ‘lifting’ the market by reducing transaction costs, for example by making better information available. The test of market transformation is whether these changes are permanent and self-sustaining or temporary.

The nature of the available policy options for moving the market is illustrated in the ‘Policy Palette’ in Figure 1-20, with the ‘push, pull and lift’ replaced by regulation incentives and information as the primary drivers, complemented by the secondary drivers of targets, facilitation and pricing. (This does not imply that these secondary drivers are less important, but rather that they are less sharply delineated.)

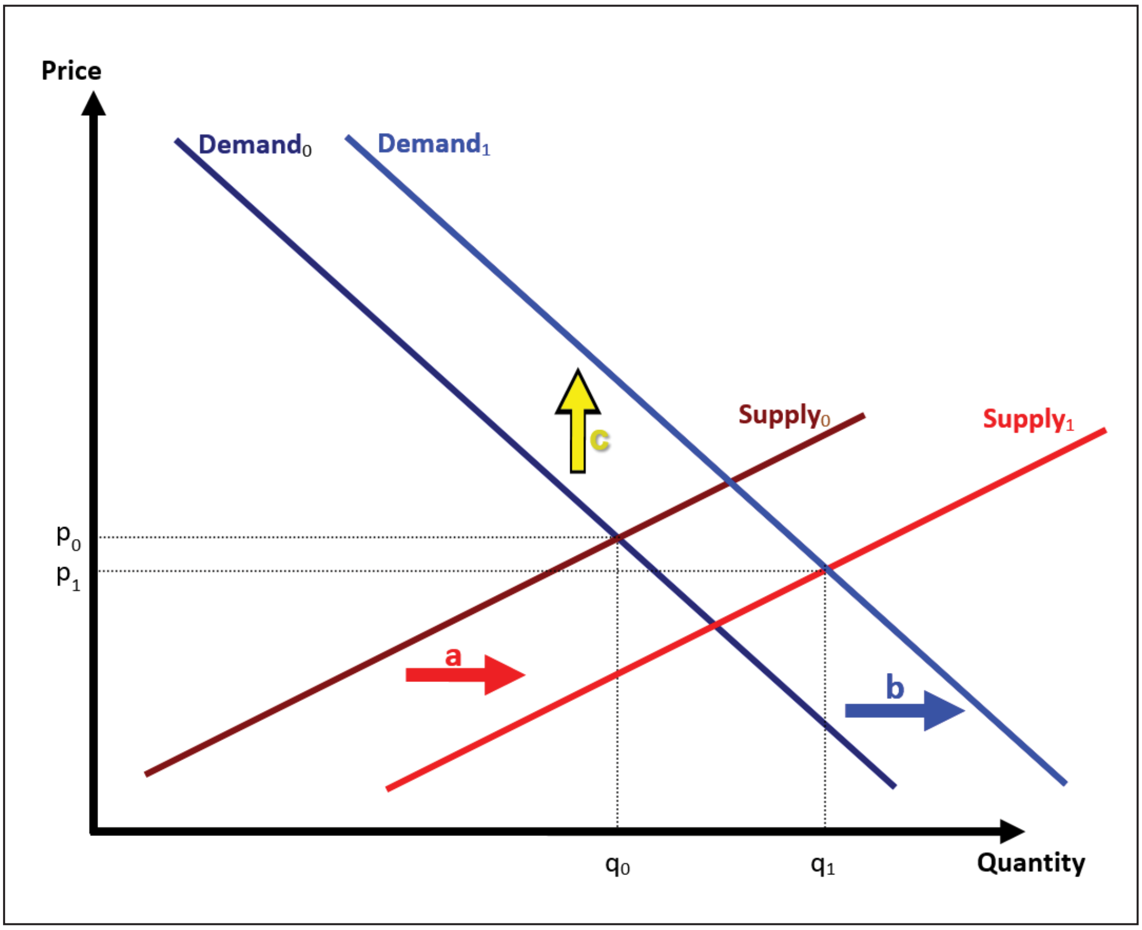


Figure 1-18 Moving the market (demand and supply)
(Dunstan et al., 2011b)

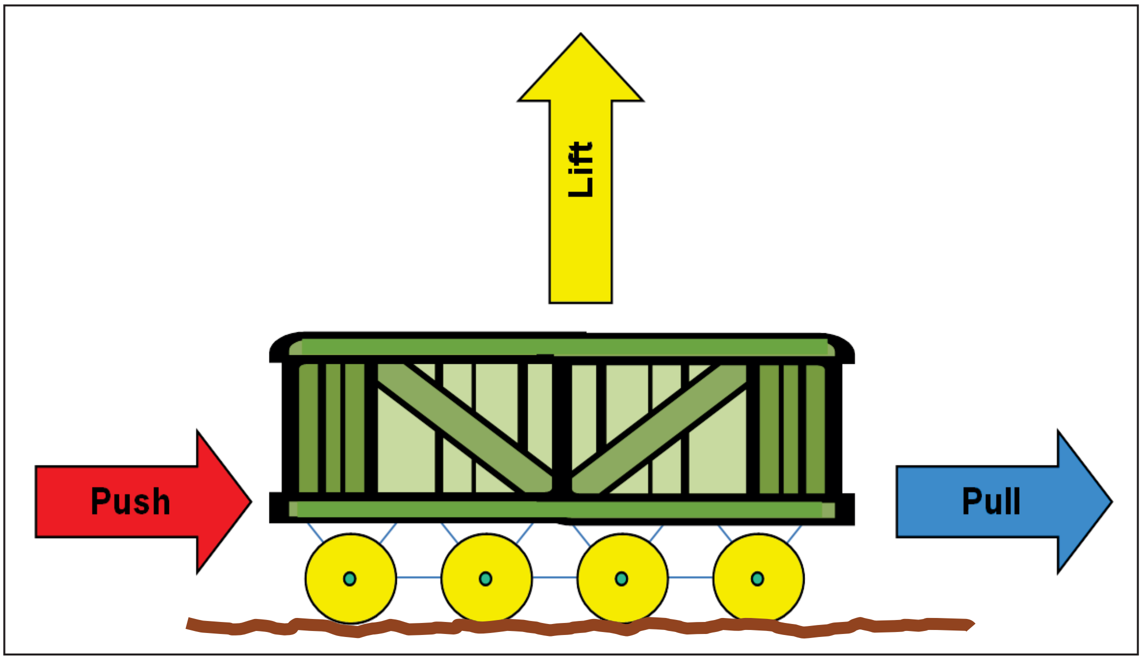


Figure 1-19 Moving the market ('push, pull, lift!')
(Dunstan et al., 2011b)

This framework offers a structure that can be further developed for classifying and coordinating policy options to support decentralised energy.

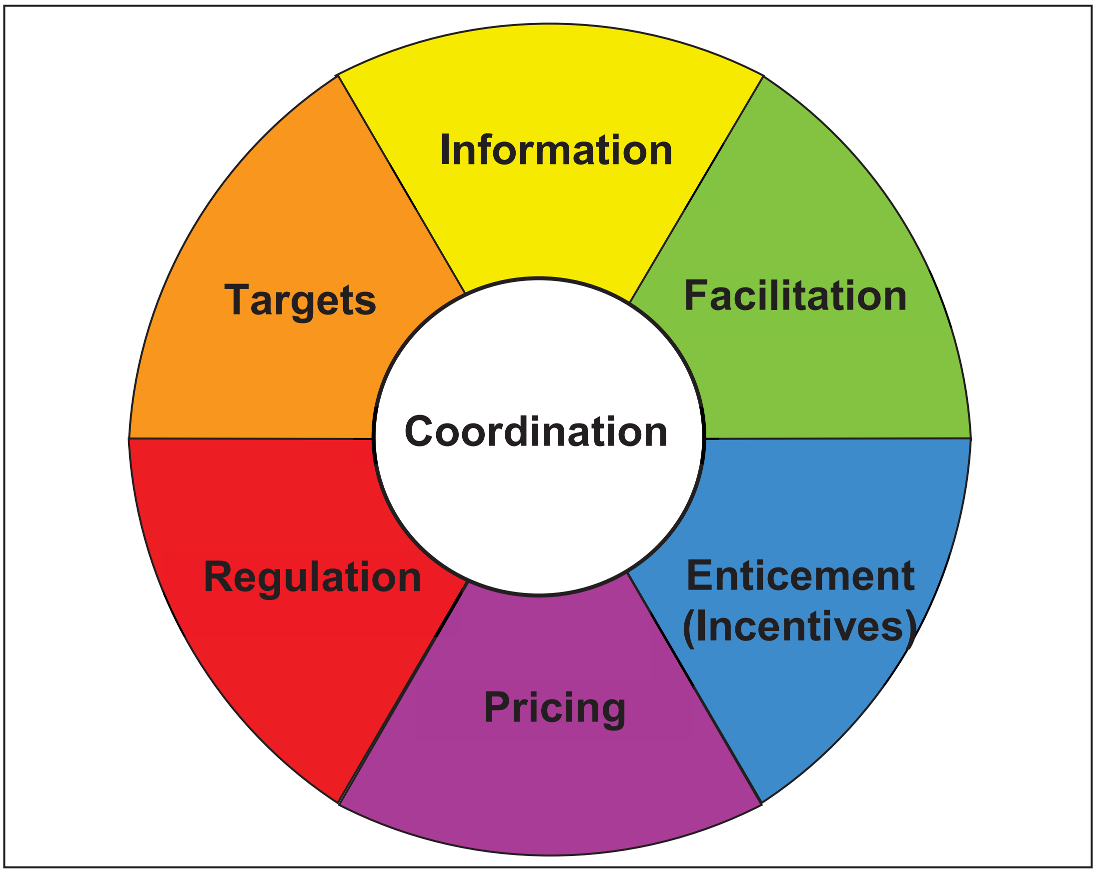


Figure 1-20 The 'PERFICT' Policy Palette of tools to 'move the market'
(Dunstan et al., 2011b)

1.5.5 Least-cost competition in electricity markets

Chapter 7 focuses on the process of change in the electricity sector and considers practical strategies to move towards a more sustainable electricity sector by applying the principles of least cost planning in competitive electricity markets.

The traditional application of LCP, which involves the full electricity supply system including power stations, is not applicable in most of the current Australian context as generation and retail capacity is not generally centrally planned and procured.

However, there are ways in which LCP can be applied to competitive electricity markets. The first involves applying LCP to distribution and transmission network businesses. These businesses remain centrally planned regulated monopolies, and are responsible for most of the billions of dollars spent in the Australian electricity sector each year. Avoiding or deferring the need for network infrastructure augmentation is probably the single biggest potential source of value for decentralised energy resources.

The second way of incorporating LCP in the competitive electricity market involves how the sector as a whole is governed. Even within the competitive parts of the electricity market, typically retailing and generation, regulators and governments retain explicit regulatory and/or implicit political powers which may be exercised should the market manifestly fail to meet community and consumer expectations[3]. The principles of least cost competition developed in Chapter 7 can be used by regulators and policy makers to assess and guide the development of the electricity system even where no formal central planning is undertaken.

1.5.6 Theories of change

While achieving effective change towards least cost outcomes is challenging, the currently accelerating transition towards decentralised energy suggests that such change is possible. The key question then is: *How can the electricity sector change to make least cost outcomes the rule, rather than the exception?*

[3] The community generally expects, and business generally accepts, that if the market manifestly fails to meet community and consumer expectations either in terms of cost or reliability then the regulator or the government will intervene, just as occurred in California following the 2001 energy crisis, and just as the governments of most developed nations have intervened in the financial markets in response to the 2007-08 Global Financial Crisis.

Chapter 7 pursues this question at a theoretical level and then at a more practical policy level. At the theoretical level, the chapter draws on the work of several theorists, including John Kingdon and Thomas Kuhn.

American political scientist John Kingdon (2003) describes the public policy reform process as greatly dependent on factors beyond simply the merits of the argument. He emphasises the roles of ‘policy entrepreneurs’ and ‘windows of opportunity’.

Historian of science Thomas Kuhn proposed a distinction between normal and revolutionary science and developed the concept of paradigm shifts. He maintained that, rather than being a simple gradual accretion of knowledge over time, the history of science involves two quite distinct processes. He saw most science as taking place within a prevailing orthodox intellectual framework, which he called a ‘scientific paradigm’ punctuated by occasional upheavals of revolutionary science.

Chapter 8 draws on both these intellectual traditions and applies them to the question of how to effect a paradigm shift within Australian competitive electricity system, in the context of the current transition towards decentralised energy in Australia.

1.6 Contribution to new knowledge

This thesis makes several contributions to new knowledge, as summarised below:

Least-cost competition: a market-based approach to least cost planning

To the extent that least cost planning (LCP) has been applied to electricity systems, it has been applied through a centrally planned system either by a vertically integrated utility or through a government planning authority (e.g. the California Energy Commission, the Danish Energy Agency). LCP has generally been considered incompatible with competitive retail and generation electricity markets, and so the objectives of LCP have been pursued through other means, such as system benefit funds (in about 24 US states) or dedicated organisations (e.g. Efficiency Vermont, the Energy Savings Trust and Carbon Trust in the UK and NSW Sustainable Energy Development Authority).

This thesis develops an original theory of ‘least cost competition’. This approach to reconciling the essential elements of least cost planning with electricity sector competition is based on five key principles: 1. purpose, 2. participation, 3. pricing, 4. all options, and 5. all costs. The thesis applies these principles to the particular case of the Australian National Electricity Market to propose practical policy and regulatory reforms within each key sector of the electricity system.

Given the global trend towards disaggregated electricity industry structures with competitive generation and retail markets with separated regulated monopoly networks, this approach offers a market-compatible approach for identifying and accessing the value of avoided network investment to support decentralised energy resources. Adopting this approach would be expected to lower bills and expedite the transition to a clean, low emission and affordable electricity sector, while encouraging greater and more efficient use of demand management and decentralised energy resources.

Network cost allocation analysis and mapping

Network cost analysis has traditionally been applied on a long-term average cost basis and/or a geographically averaged basis. The application of localised, marginal cost analysis is relatively rare. While market-based and/or administratively set 'nodal pricing' has been advocated, and in some cases applied, the effectiveness, practicality and equity of these approaches have been contentious (e.g. Sotkiewicz 2006, Green 2006, Oren et al. 1995). The NSW Demand Management Code of Practice provides a practical variant on nodal pricing based on marginal avoidable network cost, information disclosure and market testing. However, the abovementioned approach can only succeed if the market is able to access and respond to the network opportunities for DE in a timely and cost-efficient manner.

This thesis introduces the mapping of network costs as a means to facilitate market engagement and responses to the opportunities created by the approach described above. This also represents a contribution to new knowledge. The more detailed mapping of dynamic avoidable network costs provides the analytical basis on which to test this approach in a much more rigorous way. The thesis then extends this analysis further by using the DANCE model to develop dynamic "network opportunity maps" of avoidable network costs in order to describe more accurately the times, dates and costs of anticipated network capacity constraints.

This analysis is not just important in informing and encouraging the DE market to respond to requests for proposals form the network businesses. It also provides a network cost allocation method both for assessing the efficiency of network tariffs and for designing location-specific time of use pricing.

A generic decentralised energy option assessment model (D-CODE)

There are numerous economic models that are currently applied for systematic integrated assessment of energy options from greenhouse, energy and capacity perspectives. The Description and Cost of Decentralised Energy (D-CODE) model developed and used in this thesis is innovative in combining the following features:

- It is fully transparent and accessible. The operation of the model is fully described and relatively simple to use. The model has been made freely available for public download and use.
- It is fully generic and adaptable. All technology-specific assumptions are explicitly stated and subject to revision and sensitivity analysis by any model user. The model allows for selecting or deselecting technology options and includes scope for including new or alternative decentralised energy technologies.
- It is comprehensive: The model includes all significant decentralised energy technologies. The model is also able to incorporate large-scale centralised options such as coal-fired power stations.
- It is fully scalable. The model is useable for the analysis of individual DE projects and for state-wide or national option assessment and evaluation.

Market transformation analysis (PERFICT Policy Palette)

There is a further contributions to new knowledge related to the classification of policy options to 'shift the market'. In Chapter 5 of this thesis, I have described a systematic and comprehensive approach to classification of barriers to the uptake of decentralised energy and, in Chapter 6, a corresponding classification of policy tools to address these barriers.

The PERFICT Policy Palette fills a knowledge gap in the systematic classification of policy options, particularly in relation to the concept of 'Market Transformation'. From my analysis of the literature in the area, this represents an additional contribution to knowledge related to the classification of policy tools. Given the importance of "market transformation" in this field, and indeed other areas of infrastructure provision beyond energy, filling this knowledge gap is useful and important beyond its role in this thesis.

Chapter 2. The Potential of Decentralised Energy

'The future isn't what it used to be.' – Paul Valery, 1937

2.1 Assessing demand management potential in Australia

As noted in Chapter 1, one of the two key research questions this thesis addresses is:

> To what extent could greater use of demand management in the electricity sector lead to both lower costs and lower greenhouse gas emissions?

Demand management (DM) depends on using decentralised energy (DE) in place of centralised energy resources. Therefore, to assess the potential of DM to cut costs and emissions, it is necessary to assess:

- the costs and emissions of DE
- the amount of DE available to be deployed
- the amount, costs and emissions associated with the centralised energy resources that DE would displace.

This chapter addresses these questions.

This chapter begins by considering the context of the recent rise to prominence of decentralised energy and the range of benefits that it offers. The chapter then describes a novel tool that I have devised and developed, in collaboration with my colleagues at the Institute for Sustainable Futures, as part of my PhD research: the Description and Cost of Decentralised Energy (D-CODE) model. Section 2.2 discusses the purpose, the design principles and the capability of the model. Section 2.4 outlines the D-CODE methodology, data requirements, and outputs, while Section 2.5 applies the model at a national scale to provide a high-level estimate of cost-effective DE in Australia and discusses some general findings and implications of the model's outputs. Section 2.6 describes the application of the model's approach to a number of real-world case studies.

The D-CODE model aims to provide an innovative, flexible and transparent analytical tool for evaluating and comparing decentralised energy technologies with each other and with centralised supply alternatives. In so doing, it seeks to provide a balanced approach to estimating the cost-effective potential of decentralised energy.

2.1.1 The rise of DE and DM in the Australian electricity sector

Demand management has been an important part of the electricity supply industry in Australia for more than 70 years. For example, residential off peak water heating has been available in Victoria since the early 1930s (Joint SECV/DITR Demand Management Project Team, 1989b, p. 5). Queensland water heater control was extended across the state during the early 1980s.

A renewed interest in demand management in Australia emerged in the mid-1980s, driven in part by concerns about the high cost and local environmental impacts of new electricity supply infrastructure and in part by the emerging issue of what was then called 'the greenhouse effect'. For example, the board of the State Electricity Commission of Victoria adopted a series of interim targets for DM in 1989, and committed to a $55 million Demand Management Action Plan (SECV/DITR Demand Management Joint Project Team, 1989b). However, subsequently the momentum for greater DM was largely lost amid the focus on competition reform and privatisation of the industry in the 1990s and 2000s. In recent years, there has a been a revival of interest in DM, particularly in Queensland and New South Wales, again driven by concerns about the impacts of new electricity supply infrastructure (in particular network investment) on electricity prices and increasing concerns about climate change and the need to find low cost responses to it (Dunstan et al., 2011e).

The pace of change in the electricity sector is accelerating. In Australia, as in other parts of the world, electricity consumption has plateaued, as consumers have adopted more energy-efficient practices and technologies (see Figure 2-1). These developments form part of the trend towards DE, which is now so pronounced in Australia that the volume of electricity supplied from centralised power stations is not expected to return to its previous high of 2008/09 at any time during the current 10-year planning horizon to 2023/24 (AEMO, 2014). By contrast, decentralised energy in the form of both solar PV and energy efficiency (the top two segments in Figure 2-1) are forecast to grow strongly over this period. These trends raise the credible prospect that centralised electricity supply may *never* again reach its historical high in Australia of 2008/09.

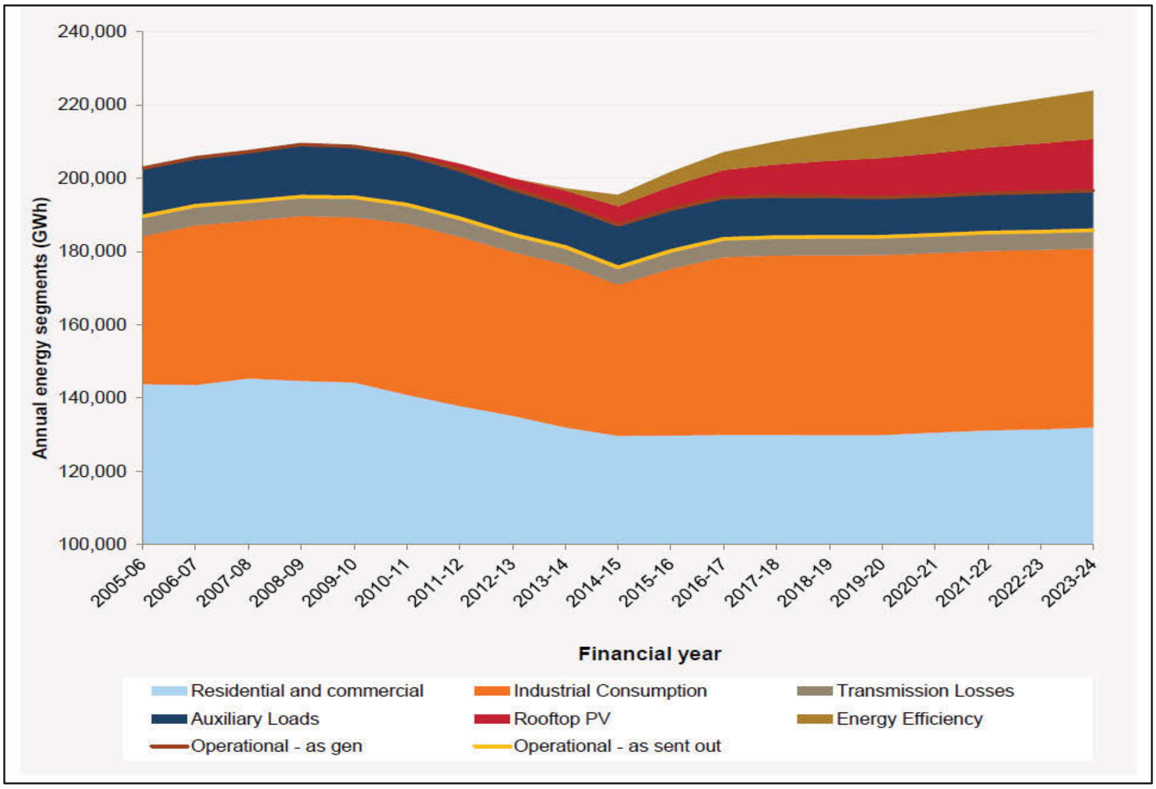


Figure 2-1 Electricity consumption in the National Electricity Market (AEMO, 2014)

Figure 2-2 highlights what a dramatic change this is from the period 1960 to 1985.

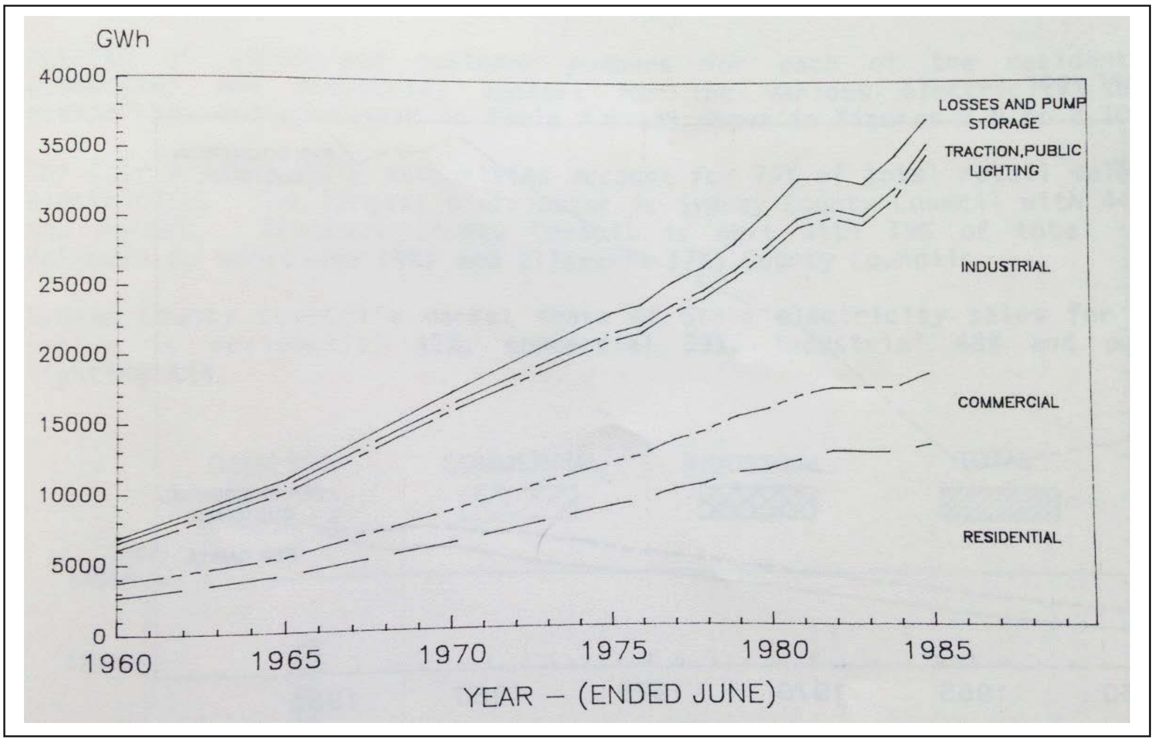


Figure 2-2 Electricity consumption in NSW (1960 to 1985)
(Energy Authority of NSW, 1986)

The period depicted in Figure 2-2 was the high growth period during which most of NSW's current electricity generation and transmission infrastructure was built.

These data raise the question of why electricity consumption growth has disappeared. Saddler (2014) has undertaken a detailed analysis to answer this question, as illustrated in Figure 2-3 in relation to business electricity consumption across the National Electricity Market and Figure 2-4 for residential electricity consumption.

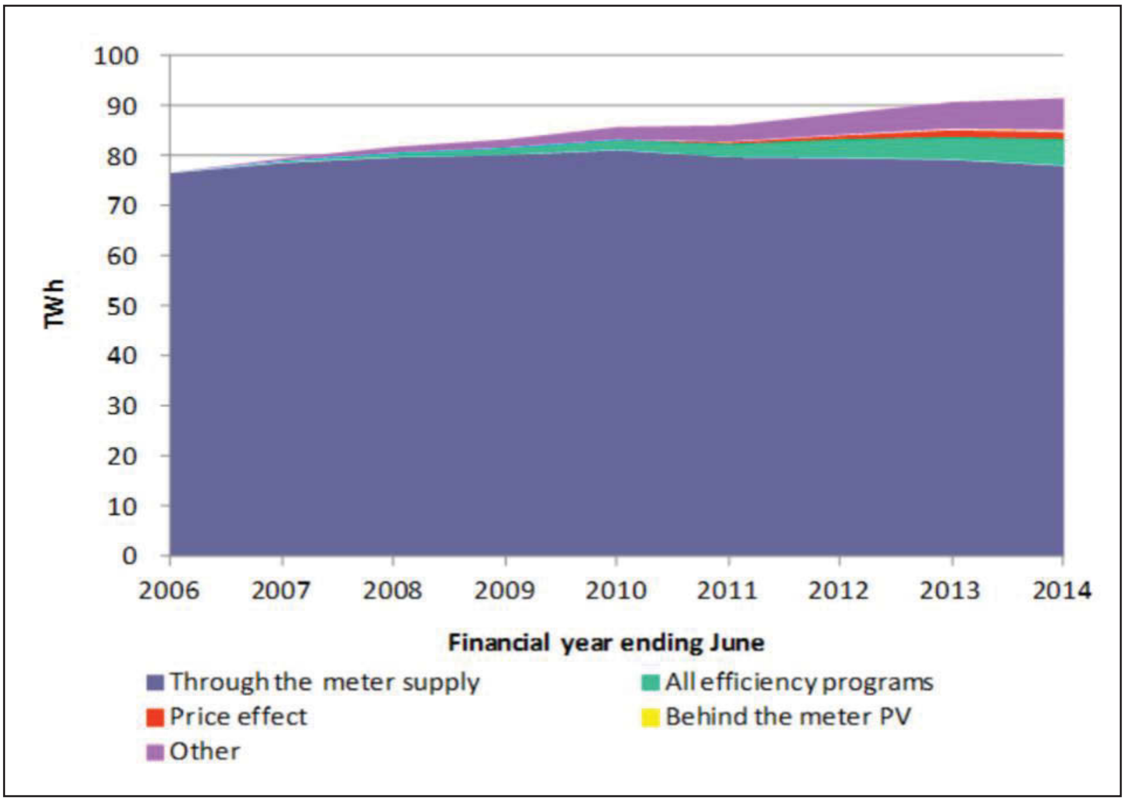


Figure 2-3 Contributors to change in business electricity demand in the NEM, 2005-14
Source: Saddler (2014, p. 14)

In both cases, it is apparent that DE, in the form of energy efficiency, and to a lesser extent behind-the-meter solar PV, is the major contributor to this levelling off of demand.

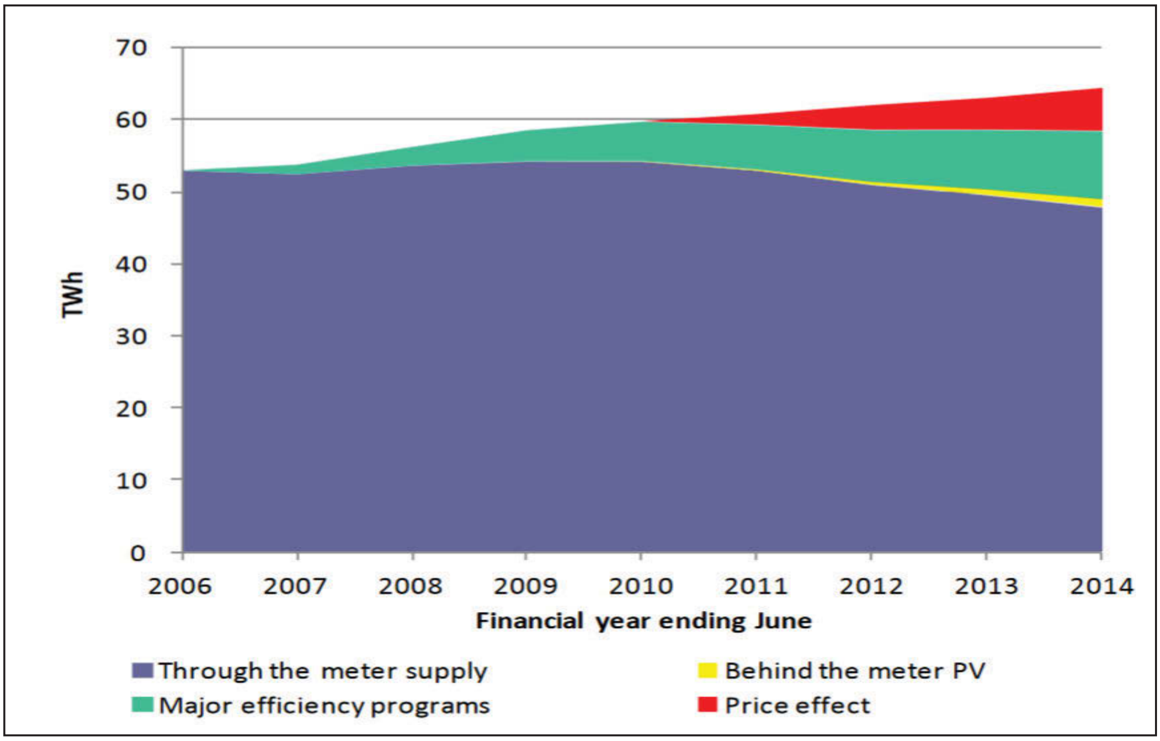


Figure 2-4 Contributors to change in residential electricity demand in the NEM, 2005-14

(Saddler 2014, p. 19)

However, while energy consumption has fallen and is forecast to remain flat in future in the NEM, peak demand is expected to continue to rise, as shown in Figure 2-5.

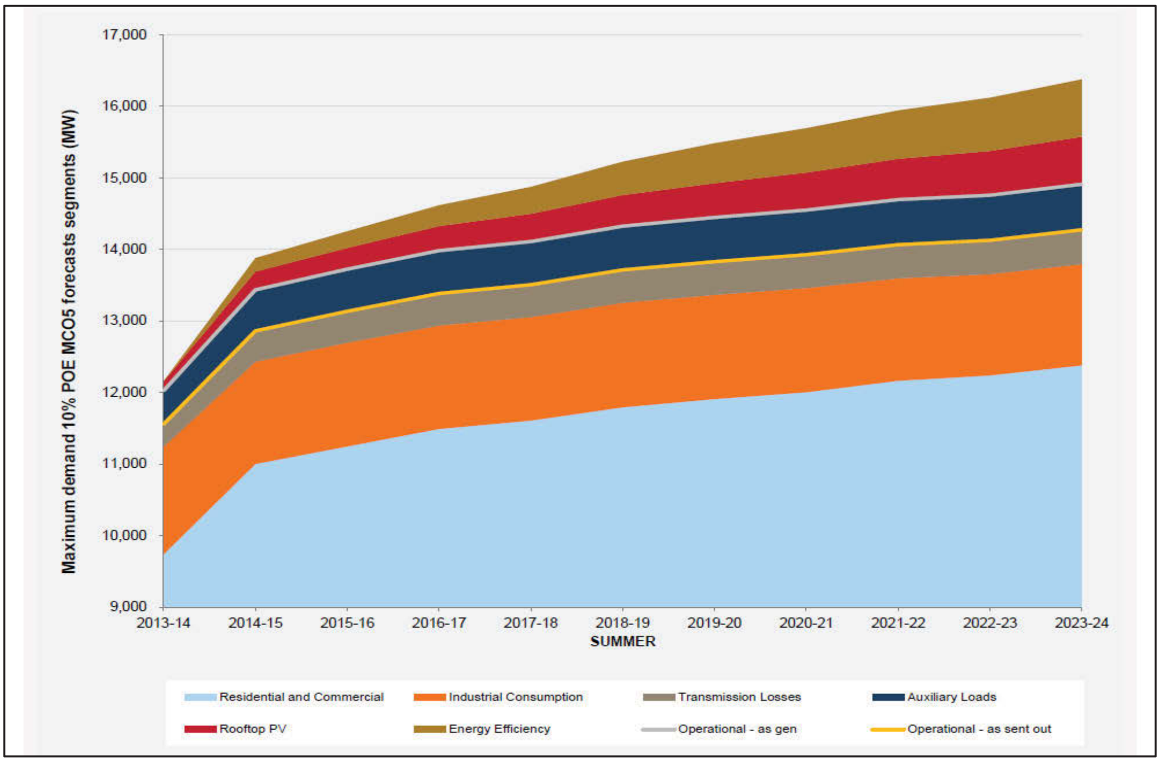


Figure 2-5 Forecast maximum electricity demand in NSW

(AEMO, 2014)

This is likely to lead to increasing costs and falling sales volume from which to recover these costs.

These changes are causing electricity generators, retailers and network businesses to reconsider what it means to be a successful utility in the 21st century. For Australian energy utilities, the traditional business model based on increasing sales of electricity or throughput of kilowatt hours is under threat. In response, some utilities are developing strategies to try to slow these emerging trends (Gifford 2014; Morris 2014), while others are changing their business strategies to try to take advantage of these trends (Parkinson, 2014).

2.1.2 Benefits of decentralised energy

For decentralised energy to fulfil its potential, it is important that all relevant benefits and costs are identified, understood and evaluated. For example, a key advantage of decentralised energy technologies is that they meet energy needs at or near the point of use, and thereby reduce the need for electricity network infrastructure. This feature is often underestimated, both in economic evaluations and in regulatory processes, On the other hand, electricity network operators and consumers often have concerns over the impact that decentralised energy technology may have on their capacity to manage the network and provide reliable energy supplies.

To evaluate the potential of decentralised energy, it is essential to identify and assess all relevant benefits and costs. For example, potential benefits of decentralised energy include:

- lower costs
- lower greenhouse gas emissions
- improved fuel efficiency
- exploitation of lower cost fuel options
- lower network system losses
- managed peak load, resulting in reduced and optimised network investment
- other network benefits, such as voltage support and reduced reactive power losses
- increased reliability of supply
- improved energy security
- provision of system ancillary services, such as, frequency control, spinning reserves and black start capability
- enhanced social equity and delivery of social benefits.

Of course, the costs and technical issues associated with the use of decentralised energy also need to be considered. However, numerous studies have concluded that large cost-effective potential of decentralised energy is not being realised. One such study by McKinsey and Company (2007, p. xii) found that in the United States, ‘almost 40 percent of [greenhouse gas emission] abatement could be achieved at “negative” marginal costs, meaning that investing in these options would generate positive economic returns over their lifecycle’.

Figure 2-6 below illustrates the potential for greenhouse emissions reduction in the United States as assessed by McKinsey and Company. As highlighted, a significant proportion of these abatement opportunities have a negative ***net*** cost. That is, the avoided cost associated with the measure exceeds the direct cost of achieving them. The large majority of these ‘negative cost’ options are decentralised energy resources, as highlighted below.

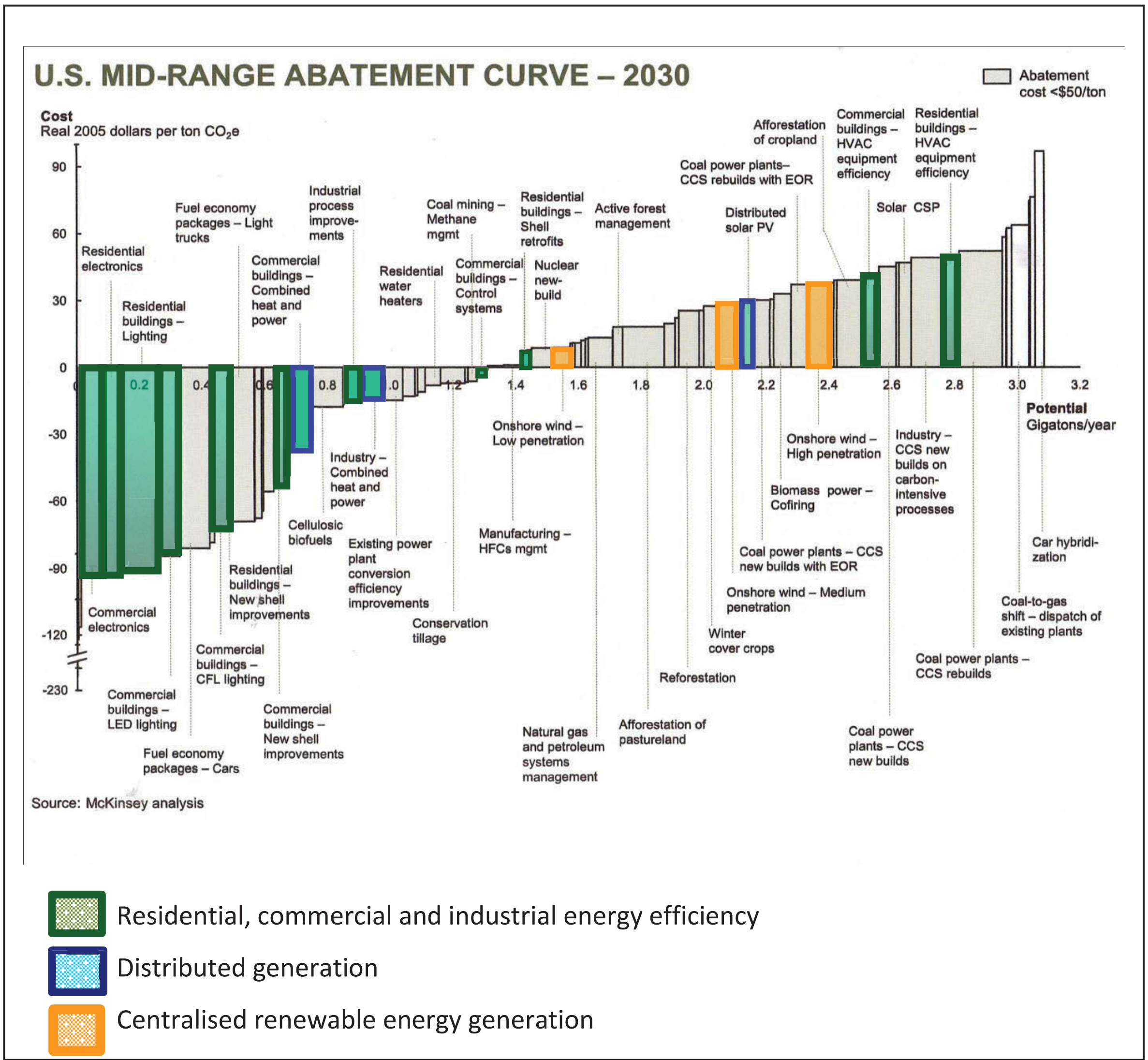


Figure 2-6 US greenhouse gas emission reduction potential (with DE higlighted)
(adapted from McKinsey & Company 2007, p. xiii)

A similar study undertaken by McKinsey and Company Australia and Climateworks for the Australian context reached similar conclusions – it found that greenhouse gas emission reductions of 35 per cent are achievable by 2030 at no net cost. See Figure 2-7 (McKinsey and Company Australia 2008, p. 15).

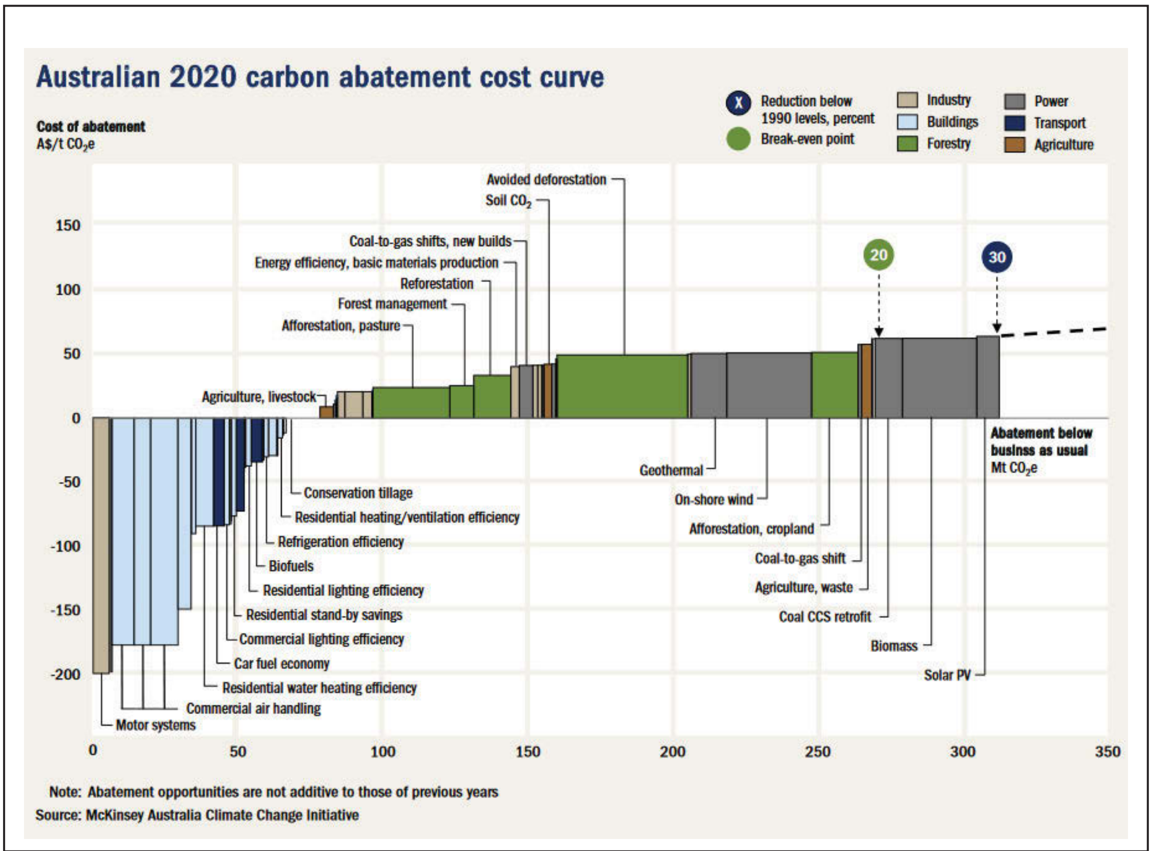


Figure 2-7 Australian carbon abatement cost curve

(McKinsey & Company Australia, 2008)

Another perspective on the relative cost of DE is provided by comparing the *gross* rather than the *net* cost of energy, as shown in Figure 2-9, which provides an assessment of the cost of energy efficiency relative to a range of supply-side options.

A third perspective on the cost effective potential for DE is offered by Thomas who focuses on energy efficiency opportunities in Germany. As shown in Figure 2-8, it is estimated that Germany could cost-effectively save more than 20 % of energy and carbon dioxide emissions within 10 years (Thomas 2016, p. 9).

To emphasise this point, Figure 2-9 compares the cost of energy efficiency to various supply-side options in the United States, highlighting that energy efficiency is the lowest cost energy resource and the lowest costs emission reduction option in the energy sector.

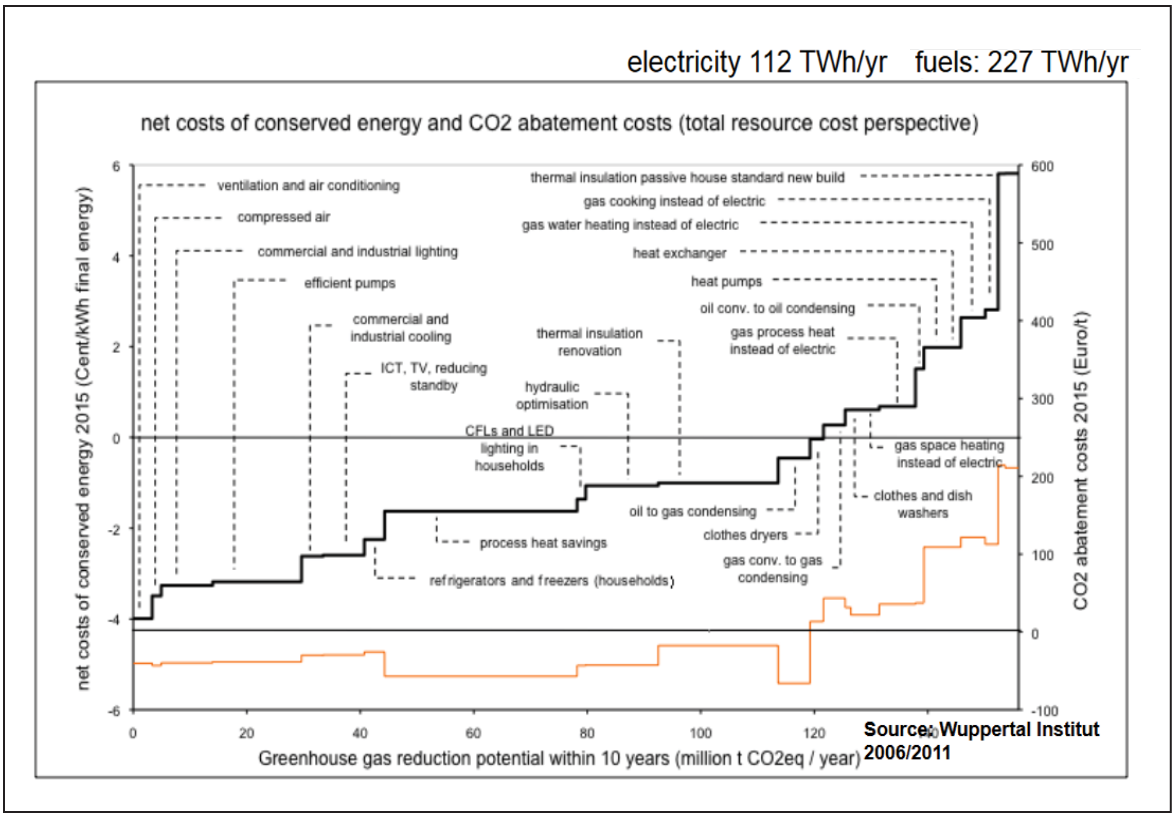


Figure 2-8 Potential energy and emissions savings from energy efficiency in Germany

(Thomas 2016, p.9)

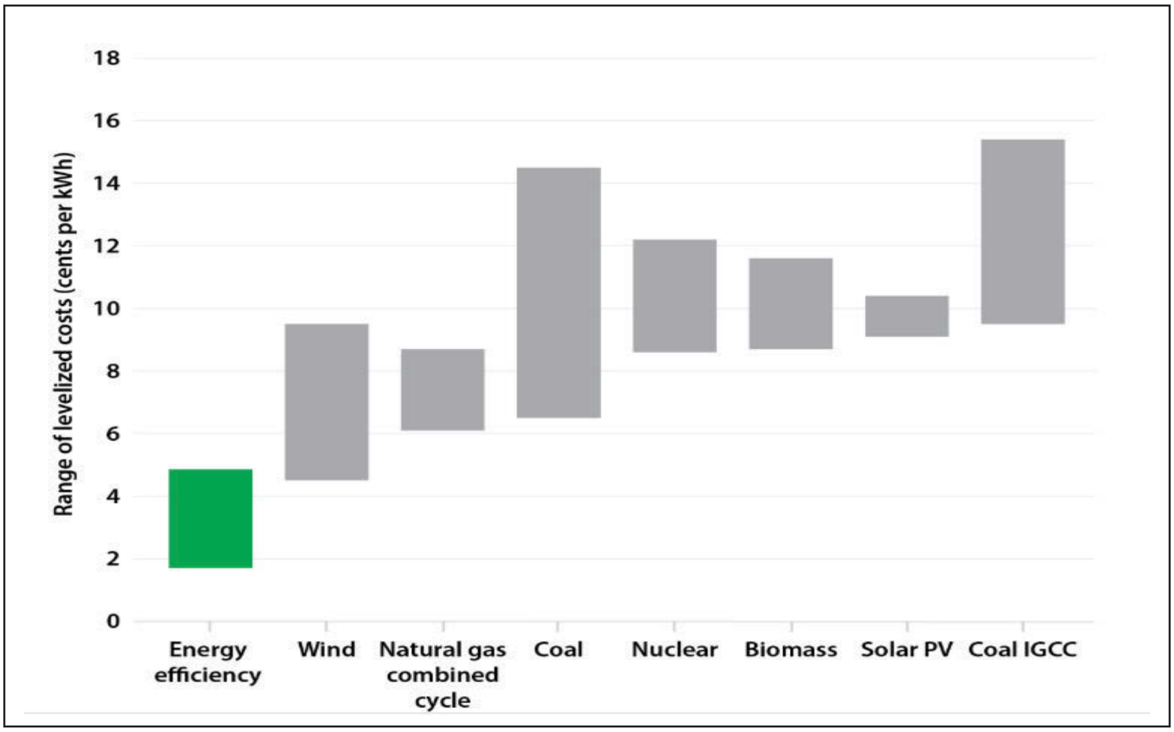


Figure 2-9 Cost of energy efficiency relative to a range of supply-side options (USA)

(Molina 2014, p. vi)

A study by Langham et al. (2010) found that the implementation of energy efficiency programs in buildings alone could reduce network augmentation costs by up to $2.2 billion each year. This is supported by the Office of Gas and Electricity Markets (OFGEM) in the UK which notes that distributed generation may be able to offer 'transmission and distribution cost savings for the UK by reducing or, in some situations, avoiding completely the costs incurred in reinforcing these networks' (OFGEM, 2007, p. 17).

On top of savings from avoided network augmentation, DE offers additional benefits including lower greenhouse gas emissions, lower network system losses, voltage support, reduced reactive power losses and local involvement and employment in electricity provision.. On the other hand, electricity network operators and consumers often have concerns over the impact that decentralised energy technology may have on their capacity to manage the network and ensure supply reliability.

2.2 Analysing the cost-effective potential of DE: the D-CODE model

One key barrier to the development of DE is a lack of the information needed to compare the costs and benefits of traditional centralised technologies, with 'decentralised energy' technologies which meet energy needs through efficient, local forms of low carbon energy supply, and demand reduction. The Description and Cost of Decentralised Energy (D-CODE) model developed for this thesis is intended to fill this gap.

An important feature of the D-CODE model's analysis is the inclusion of network infrastructure costs, which generally make up around half of the consumer energy bill – a cost usually left out of traditional energy generation cost comparisons. Whereas other models of comparable purpose are highly complex and are targeted at an expert target audience, D-CODE has been purposely designed to be versatile, transparent and easy to use. As such, it can be applied at scales ranging from the national scale to the local scale, and it can assist governments, utilities, local planners and other interested stakeholder groups to better understand the true costs of generation options, and it can make possible informed decision-making towards a cost-effective, low carbon energy future.

2.2.1 Purpose and motivation for developing the D-CODE model

The Description and Cost of Decentralised Energy (D-CODE) model aims to transcend simple benefit–cost analyses of different decentralised energy technologies by providing a robust, transparent and accessible tool that allows energy specialists, policy makers and interested laypeople to conduct their own analyses. The model incorporates all key parameters to allow the costs of technologies to be compared.

The D-CODE model is designed to be applicable nationally and to any state or jurisdiction. It includes the option of either inputting new values or selecting in-built default values based on generic average values or values relevant to a particular state or region.

There are numerous economic models that are currently applied for energy option evaluation. The D-CODE model is innovative because it combines the following features:

1. It is fully transparent and accessible. The operation of the model is simple and fully described. The model is freely available for public download and use (Dunstan et al, 2011g).
2. It is fully generic and adaptable. All technology-specific assumptions are explicitly stated and subject to revision and sensitivity analysis by the user. The model allows for selecting or deselecting technology options and it has scope for including new or alternative decentralised energy or alternative technologies.
3. It is comprehensive: The model includes all significant decentralised energy technologies. It also incorporates large-scale centralised options such as coal-fired power stations.
4. It is fully scalable. The model is useable for analysis of both individual DE projects and for state-wide or national option assessment and evaluation.
5. The model is designed to incorporate the avoided network cost data generated out of Chapter 5 of this thesis, including the DANCE model, and where quantifiable, the other benefits identified.

The D-CODE model is applied to assess the potential efficiency benefits available from greater use of decentralised energy options in the Australian electricity industry.

Fundamentally, D-CODE seeks to answer the key question: ‘What is the least cost way to ensure we meet our future electricity needs, using supply technologies and demand management opportunities available today?’ By incorporating network costs in its analysis, it offers a more accurate assessment of different energy options.[4] This removes the common

[4] The network costs are individually assigned to each technology based primarily on the how ‘centralised’ each technology option is – see Section 2.4.1 for more details on network cost methodology.

bias against DE options present in a typical levelised cost of generation analysis that ignores the *delivered* cost of electricity, including network costs. D-CODE is a timely tool which aims to a) stimulate discussion, and b) assist governments, utilities, local planners and other interested stakeholder groups in making informed decisions. D-CODE also considers the carbon emissions associated with different options.

As discussed in Section 2.3, there is a well-developed range of detailed and complex economy-wide and system-wide models in Australia and overseas. The commercial, proprietary nature of most of these models represents a significant barrier to analysis by DE advocates. D-CODE aims to complement these approaches with an open access, simple and transparent modelling tool. In the areas for which it was designed, D-CODE requires less detailed data than these other models and it is therefore more useable.

D-CODE considers compilations of decentralised energy technology data such as the DES Compendium (SEDA 2002) and system-wide and long-term planning tools such as LEAP (Heaps 2008) and DISPERSE (Gumerman, Bharvirkar et al. 2003).

2.2.2 Foundations of the D-CODE model

The inspiration for the D-CODE model was the 'Distributed Energy Solutions (DES) Compendium'[5] (SEDA 2002). The DES Compendium was developed to assist the Independent Pricing and Regulatory Tribunal (IPART) of NSW (IPART)[6] in its *Inquiry into the role of demand management and other options in the provision of energy services* (2002). This inquiry investigated the cost and thereby the economic feasibility of DM and distributed energy in providing the state's energy services. The DES Compendium included 35 feasible DE technologies, assessed for both cost and potential load capacity. Technologies are 'generic' in that they are categorised in groupings such as 'commercial energy efficiency' and 'industrial energy efficiency' and cover contribution to peak load and energy generation, average and marginal generation costs, and fixed plant costs as well as emissions and standard technical factors required to compute concept-level economic feasibility.

The DES Compendium provided an accessible, transparent, well-referenced database of information needed to inform preliminary assessments of decentralised generation and non-

[5] I developed this resource over several years with the support of colleagues at the Sustainable Energy Development Authority of NSW.
[6] At that time IPART was also the economic regulator for electricity distribution network businesses.

network alternatives to network expansion. The D-CODE model creates a platform to harness the basic information provided in the DES Compendium and it allows scenarios to be built up to assess the relative cost-effectiveness of DE options across any relevant jurisdiction, while providing the flexibility and transparency to be useful to a range of stakeholders. The model allows the benefits of DE resources to be considered from either the perspective of emissions reduction or the perspective of energy service provision.

The D-CODE model aims to incorporate the best and most up-to-date cost and technical data available. Further, through linkage with the Dynamic Avoidable Network Cost Evaluation (DANCE) model, which identifies the local value from deferred or avoided network augmentation, the 'total value' of decentralised energy options at specific locations on a congested grid system can be determined.

2.2.3 D-CODE design principles

The D-CODE model is based on the following three design principles:

Accessibility: The model is freely available for download and use by the members of the Australian electricity industry and wider community. The model is simple to use and understand relative to models of comparable purpose.

Transparency: The operation of the model is fully described and all data inputs and calculations used to generate costs are fully observable to the user. Data sources and conversions are fully disclosed.

Flexibility: Importantly, all input data are subject to revision and adjustment by the model user, enabling user-operated sensitivity analysis. Furthermore, the model allows complete flexibility when constructing scenarios. For example, the user can select the scale of analysis (national, NEM, state), select which technologies will be included each scenario, and select policy, supply and demand settings to influence the future energy shortfalls and additional supply requirements.

Functions

There are two main functions performed by the D-CODE model:

- the generation of levelised cost curves to compare supply- and demand-side options side-by-side

- an Optimal Mix Analysis (OMA), whereby the model generates the 'lowest-cost' mix of supply- and demand-side technologies and opportunities available to meet future energy and capacity shortfalls.

Levelised cost curves

D-CODE generates levelised cost curves that enable a comparison of the costs and potential of different technologies to deliver electricity services. D-CODE integrates both demand- and supply-side options on the same curve, allowing straightforward comparison for least cost electricity service delivery.

As some technologies are used primarily to address energy generation shortfalls and others are used more to address shortfalls in peak power demand, the data is calculated and presented on two types of cost curves:

- annual energy generation (in $/MWh, see Figure 2-10)
- peak power generation (in $m/MWp, see Figure 2-11).

In both Figure 2-10 and Figure 2-11, the vertical axes represent the costs, which are broken down into components (represented by different colours) to provide insight into the cost composition of each technology. The horizontal axes represent the quantity of technology that could potentially be developed within the nominated region and timeframe. Importantly, these graphs include network cost estimates assigned to each technology, and therefore avoid the inherent bias against DE that is present in typical levelised cost comparisons. DE options are labelled in red.

Each cost curve serves a specific purpose. For example, if the electricity system in question requires additional energy supply, the energy cost curves (Figure 2-10) will provide an indication of the cost of installing additional energy at the required scale over the planning timeframe. On the other hand, if the electricity system in question is approaching a peak capacity constraint, the peak power generation curve (Figure 2-11) provides an indication of the cost of installing the required additional capacity over the planning timeframe. However, often an electricity system may require both additional annual energy generation and additional peak power generation. The Optimal Mix analysis is designed to select the lowest-cost mix of technologies to satisfy these dual objectives (see Section 2.4.2).

Cost curve flexibility

The user can choose to display up to 34 inbuilt technologies and demand management opportunities in the cost curves. In addition, the user can manually enter up to nine additional technologies, provided they have the necessary input data available. The user also has the option of selecting the jurisdiction (state, national or custom) and year of analysis (out to 2020). Other market-wide parameters that can be adjusted include the carbon price, gas price and weighted average cost of capital (WACC).

All input data specific to each technology is clearly displayed on the 'input datasheet' within D-CODE. The user has the option to override any inbuilt data, simply by selecting the relevant cell and typing the data in. A full description of the model's flexibility and user-friendly features is contained within the D-CODE user manual, provided as a separate document downloadable along with the model itself (Cooper, 2011).

Data transparency

An extensive literature review was undertaken to select the most appropriate input data for use in the cost curves. The default data was selected based on premises of being:

a) close to the mean of the data from the literature
b) from a reputable source
c) rigorous in its calculation methodology.

To view the source of the data in the model, the user simply has to scroll the cursor over the relevant data cell within the 'input datasheet' tab. Similarly, all technology-specific calculations, including cost calculations, are clearly contained within the model ('output calculations' tab). The D-CODE model is supplemented by the D-CODE data compendium.pdf file, which contains a summary of input data, the calculation methodology, and referencing for each inbuilt technology and model assumption.

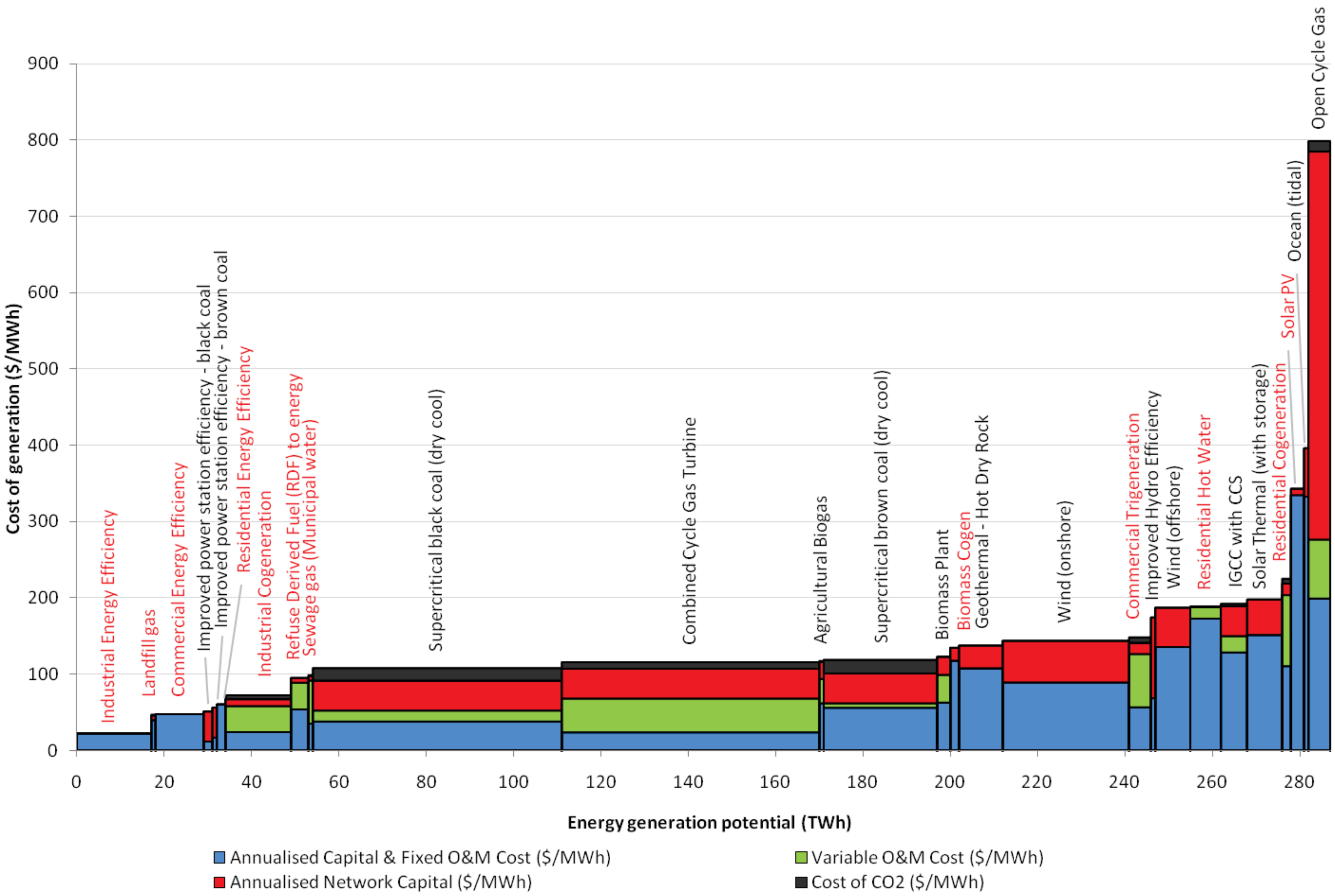


Figure 2-10 Cost and potential of energy generation ($/MWh)
(Dunstan et al., 2011c)

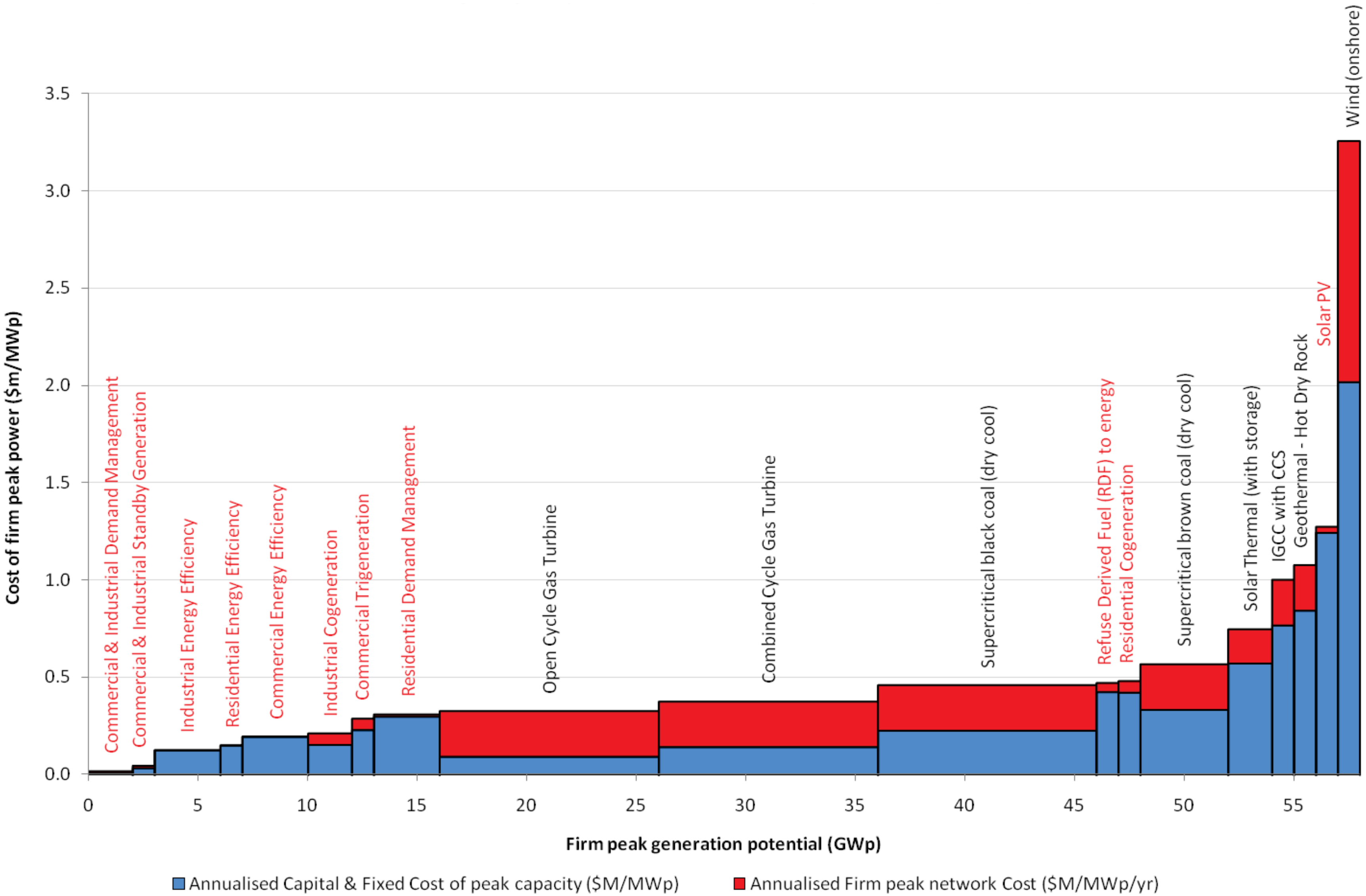


Figure 2-11 Cost and potential of supplying peak power ($m/MWp)
(Dunstan et al., 2011c)

2.3 Other approaches to assessing decentralised energy potential

To learn from precedents and to contextualise the D-CODE model, at the time D-CODE was first developed in 2010 a review was undertaken, principally by my ISF colleagues, of the numerous existing models and approaches from around the world that have been used to assess the costs and benefits of energy technology options (see Dunstan et al. 2011c). The review identified several modelling tools with a similar purpose, but none with the same approach and characteristics as the D-CODE. The full review is included in Dunstan et al. (2011c). The following summary draws on this review and complements it by also considering other modelling approaches.

This summary also draws on a Lawrence Berkeley National Laboratory (LBNL) review of 52 modelling tools and approaches for energy sector service provision (Gumerman, Bharvirkar et al. 2003), primarily from North America with some international efforts. The LBNL review reported a wide range of purposes, target audiences and commercial intents across the various models. Underlining the importance of having a clear purpose, audience and viable strategy for dissemination and use of such models, many of the models considered are no longer available.

McKinsey carbon abatement cost curve

Cost abatement curves are a common tool for assessing economic impact alongside environmental criteria such as energy consumption or greenhouse gas emissions. The most popular is the McKinsey greenhouse gas abatement cost curve released in 2007.

McKinsey and Company (2008) developed a least cost carbon abatement curve (see Figure 2-7) for comparing least cost solutions across a variety of industries and sectors. The costs and carbon production figures used in the curve are calculated relative to a 'business as usual' (BAU) approach in which Australia continues to generate the bulk of its electrical energy from coal and undertakes few measures to increase the efficiency of energy usage. McKinsey and Company plot various greenhouse gas (GHG) reduction strategies with the cost of GHG emissions (relative to the BAU baseline) on the vertical axis and GHG reduction potential on the horizontal axis (see Figure 2-7).

The McKinsey carbon abatement cost curve is useful for comparing the costs of carbon abatement measures, but it does not model the dynamics of the electricity sector (peak demand and capacity, network constraints, etc.). Consequently, it is not comparable to the D-CODE model in purpose and application.

From Figure 2-7 above, it can be seen that motor system improvements and commercial air handling improvements will collectively reduce GHG production in Australia by about 30 Mt CO2-e annually, and that the current net cost of implementing these measures is negative. The negative cost of CO2-e emissions here indicates that if market barriers can be overcome, these measures are already cost-effective.

It is reported by McKinsey that ‘power offers the greatest volume of abatement potential, at 39 per cent of the total’ (McKinsey & Company 2008). D-CODE has sought to expand on the opportunity for greater emission reduction by considering the true costs of power generation, including network costs that are often ignored when comparing options for achieving a secure, reliable energy supply. D-CODE integrates demand- and supply-side approaches and can be used to plan least cost infrastructure decisions for electricity service delivery.

LEAP: the Long-range Energy Alternatives Planning System (LEAP)

LEAP was developed by the Stockholm Environment Institute for global application in medium-to long-term policy analysis in the energy sector and for broader climate change mitigation (Heaps 2008). It makes possible the economy-wide modelling of different energy and resource systems, and tracks energy consumption, production and resource extraction and associated greenhouse and air pollution emissions. Like D-CODE, its design criteria include flexibility and ease of use to ensure that the user base is not confined to energy experts. LEAP allows for a broad range of modelling methodologies, from ‘bottom-up end-use accounting techniques to top-down macroeconomic modelling’ on the demand side (Heaps 2008). It also allows ‘a range of accounting and simulation methodologies that are powerful enough for modelling electric sector generation and capacity expansion planning, but which are also sufficiently flexible and transparent to allow LEAP to easily incorporate data and results from other more specialized models’ (Heaps 2008) on the supply side.

Other key features of LEAP similar to the D-CODE model include:

- Scenarios can be created and managed to compare the economic, social and environmental implications of different independent and combined policy options.

- The initial data requirements are small, but LEAP has the flexibility needed for detailed inputs if data is available, allowing simple and rapid initial analysis, with room for greater complexity as required.

LEAP model outputs are generally more complex and long-term than those of the D-CODE, with analyses generally performed on an annual basis over a period of 20 to 50 years. LEAP is a powerful tool that covers similar territory to D-CODE, but it is not specifically targeted at decentralised energy resources, so it may be less effective in communicating about decentralised energy options to policy makers and utilities. As noted, LEAP is also more complex than D-CODE. There may be potential for some useful integration and collaboration involving D-CODE and LEAP. LEAP is only free to users in developing countries and to students. This is a barrier to its wider use.

Next Generation Utility (NGU)

Next Generation Utility (NGU) was developed by the Energy and Resources Team at the Rocky Mountain Institute in Colorado, USA (RMI) (Rocky Mountain Institute 2009). The project shares common goals with the D-CODE model in providing information towards replacing traditional centralised baseload generation with dynamic decentralised demand- and supply-side responses in order to reduce carbon emissions and improve the cost competitiveness of the electrical system. The primary focus is on matching complex supply and demand curves, not only by using diversified low-carbon supply options, but also through dynamic load shifting to better utilise times of greater renewable energy supply.

The model creates a simplified production and dispatch model at the utility system level using hourly consumption and generation data for one or more year. This is significantly more complex that the D-CODE approach. Like D-CODE, NGU aims to be applicable to both simple and larger-scale scenarios, with a modular design. The model is scalable from the city level to an entire continent.

Data incorporated from utility partners includes: hourly load profile; load breakdown by sector/end-use; avoided costs; variable renewable production data; outage/reliability data; existing and planned generation mix; ancillary service details; and dispatch method. Outputs include supply profiles ranked in order of least short-run marginal operating cost, CO_2 emissions, cost and reliability. For modelling future scenarios the user controls CO_2 pricing, energy growth rates, energy efficiency and energy storage penetration.

NGU is a very powerful model that takes an engineering approach that uses cost data rather than an economic modelling approach. The data needs for NGU are far greater than for D-CODE due to the complexity of the hourly dispatch model. The NGU is no longer available and it appears that RMI has discontinued use of the model.

The Full Cost of Electricity

The Full Cost of Electricity is an initiative of the Energy Institute of the University of Texas to ‘identify and quantify the full-system cost of electric power generation and delivery – from the power plant to the wall socket’ (Rhodes et al., 2016, p. 17). It is intended to inform public debate by providing a holistic assessment of the total direct and indirect costs of generating and delivering electricity. Its focus is only on the cost of generation in the US, so it does not engage with demand-side technologies and costs. However, it does create powerful and compelling maps of optimal generation investment by cost for a range of scenarios, as illustrated in Figure 2-12.

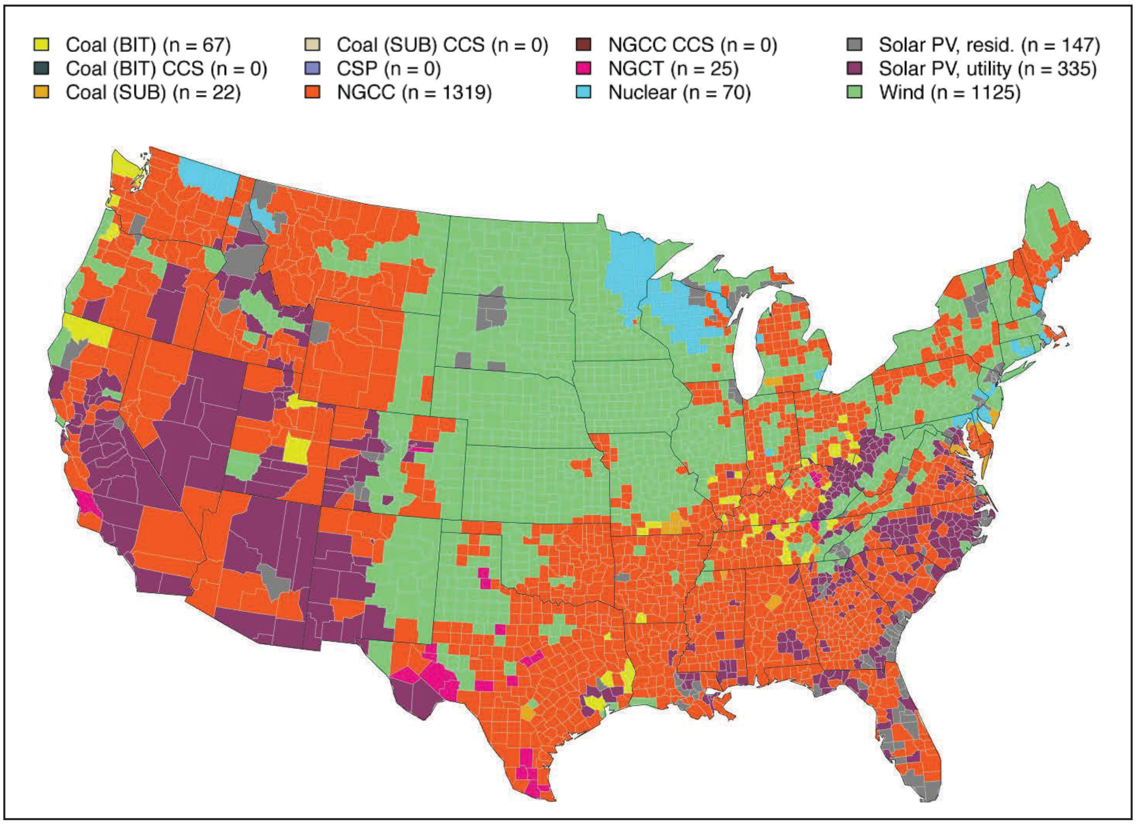


Figure 2-12 US minimum cost generation technology by location, excluding externalities (Rhodes et al., 2016, p. 17)

Resources for the Future (RFF) Haiku Electricity Market model

The RFF Haiku model simulates regional and interregional electricity markets in the USA. It is designed to '[capture] the detail of the national electricity market within a framework that can be used as a laboratory for exploring market economics and public policy' (Paul and Burtraw 2002). Haiku breaks the USA into 13 subregions and analyses temporal effects over three seasons, each comprising four time blocks. Demand is categorised by sector (residential, commercial and industrial) for which numerous characteristics are simulated, including capacity investment and retirement (Gumerman, Bharvirkar et al. 2003). Both regulated and competitive (including a time-of-use option) pricing scenarios are modelled to allow the determination of the implications of these pricing models. Haiku assumes that there are no transmission constraints within regions (Paul and Burtraw 2002), and so it is unsuitable for use in harmonising with network constraints analysis such as that provided by the DANCE model (see Chapter 4). The model is reported to be freely accessible, but does not appear to be currently available online.

Australian MARKAL (MARKetALlocation) model

The MARKAL framework was developed through the International Energy Agency Energy Technology Systems Analysis Program and was enhanced and adapted for the Australian national energy system by the Australian Bureau of Resource Economics (ABARE) (Naughten 2002). The model's main purpose is, in policy analysis, to simulate a range of technical and economic issues facing the energy sector. It can incorporate existing and potential energy supply technologies (to 2040) and some demand-side modelling. It has the capability to assess seasonal and diurnal demand variations across six independent but interconnected regions, which are based on the Australian states.

The model has been used to simulate the effects of the Mandatory Renewable Energy Target (MRET) policy and the economic impacts of combined cycle gas turbine generation in Australia (Naughten 2003). A similar US model, called the National Energy Modelling System (NEMS) with its 'Electricity Market Module (EMM)', is available from the Energy Information Administration (Energy Information Administration 2009; Gumerman, Bharvirkar et al. 2003). However, it is not very transparent and is not well suited to capturing distribution network constraints.

The Electricity Asset Evaluation Model (EAEM)

The Electricity Asset Evaluation Model (EAEM) is held by Energy Resources International, Inc. and is a tool developed with the support of a National Science Foundation grant in the US. Inputs include characteristics of the current generation, transmission, and distribution systems as well as projected loads. The EAEM is able to identify the location and timing of system asset investments that meet user-specified goals, including 'determining costs and benefits of alternative options or scenarios, alleviating transmission and/or distribution system congestion, and increasing system reliability' (Gumerman, Bharvirkar et al. 2003). Most notably, the EAEM was used by McCusker and Siegel (2002) to assess the benefits and costs of distributed generation options to address network congestion in electrical systems of Florida and Mississippi. However, the model makes no assessment of demand management.

PowerFactory

German company DIGSilent developed PowerFactory as a detailed and flexible tool for power system analysis. It is a proprietary, vertically integrated model which includes categories of analysis such as 'generation', 'transmission', 'distribution' and 'industrial'. The PowerFactory software is designed to be flexible and accessible and is implemented as a single executable program compatible with Windows XP and Vista (DIGSilent, 2015). PowerFactory is primarily a network modelling tool rather than a DE assessment tool. It has a focus on issues such as power flow, fault analysis, and harmonic load-flow analysis. However, it does include an extensive database and recent versions of the model have included some DE technologies such as battery storage and distributed solar PV systems.

HOMER and RETScreen

For site-specific applications of DE, the HOMER (NREL 2009); and RETScreen (Natural Resources Canada 2009); models are free of charge, accessible via web download and are powerful tools that begin with bottom-up end-use assessments with the ultimate aim of determining the financial and environmental costs and benefits of clean energy supply and efficiency options. They are well suited to site owners looking to invest in distributed generation options, however these models have little flexibility in accounting for energy efficiency and load management.

The above review indicates that there is a gap in the energy planning research area that D-CODE can fill. In particular, traditional levelised cost of generation analyses do not properly take into account the cost of network transmission and distribution, and they understate the costs of centralised electricity generation relative to distributed generation (Electric Power Research Institute 2010; OECD 2010). D-CODE incorporates network costs in its assessment to provide a more accurate comparison of the costs of centralised and decentralised energy options. Existing models which have attempted to incorporate a more accurate reflection of DE costs and benefits are highly complex and sophisticated (NREL 2009) or no longer available (e.g. Rocky Mountain Institute 2009). The strength of D-CODE is not in complex modelling power, but in its simplicity, transparency and accessibility.

2.4 Features and limitations of the D-CODE model

2.4.1 Network cost calculation methodology

The D-CODE cost curves are unusual in that they include the estimated average network cost impact of each generation type. This subsection briefly describes the method D-CODE uses to assign network costs.

The amount of network capital expenditure will depend on the extent of the network capacity constraints, which often occur locally at the distribution zone level. D-CODE’s sister model, the Dynamic Avoidable Network Costs Evaluation (DANCE) model, also produced by ISF under the iGrid program, maps local network constraints using Geographical information Systems (GIS) to provide a dynamic picture of potential avoidable costs associated with decentralised energy for utilities and energy planners (see Chapter 4). D-CODE, on the other hand, generally looks at the energy system with a higher level focus and therefore accounts for these typically local network investments by using an average annualised figure for an entire jurisdiction.

My colleagues at the Institute for Sustainable Futures and I have used this approach to account for the avoided network infrastructure costs from energy efficiency measures in a state by state analysis (Langham et al. 2010a). Updated figures from this work, as shown in Table 2-1, are used in D-CODE as the ‘default network capital costs’ of network cost associated with new centralised supply generation.

Table 2-1 Network cost factors used in D-CODE (Langham et al. 2010a)

Jurisdiction	$mill/MW per year
National	0.22
NSW (incl. ACT)	0.35
Victoria	0.11
Queensland	0.21
South Australia	0.37
Tasmania	0.23
Western Australia	0.08
Northern Territory[7]	0.22

Where peak demand is increasing and leading to peak power supply shortage, each MW increase of peak demand that is met through expanding centralised generation will also require a subsequent expansion in network infrastructure to supply the additional power to households. The figures in Table 2-1 are the average annual network costs to accommodate the additional peak demand through traditional means of increasing electricity network infrastructure supply capacity. At the national level, this represents $0.22 million per MWp (megawatts peak capacity) per year. Yet if a megawatt of capacity was avoided through peak reduction via energy efficiency, for example, the cost associated with network expansion would be avoided, meaning that zero additional network costs would be incurred.

D-CODE extends this methodology to assign 'network cost factors' to each technology or demand management program. The network cost factor is simply defined as the magnitude of transmission and distribution costs relative to the default network capital costs shown in Table 2-1. In other words, the network cost factor can be viewed as the extent to which a technology or demand management program is centralised, where 100% equals complete centralisation (i.e. baseload coal generation) and 0% equals complete decentralisation (i.e. demand reduction). For example, if a relatively decentralised technology such as commercial trigeneration is assigned a network cost factor of 25%, then the annualised network cost would be $0.22m/MW x 25% = $0.055 million or around $55,000 per year per MW of peak generation capacity installed.[8]

[7] Northern Territory was assigned the national average figure due to a lack of local data.
[8] Note that these network costs are entirely independent of upfront capital costs to connect to the grid, which are typically assumed as capital contribution costs paid by the project proponent.

Minimal research exists on the impact that installing individual technologies has on network investment. Therefore, ISF uses conservative estimates to assign network cost factors to individual technologies. For example, the use of small-scale solar photovoltaic cells, a highly decentralised form of electricity generation, has a network cost factor of 5% and is not assumed to be zero because of network issues like voltage rise which have been found to occur when their installation is widespread (Ergon Energy 2010).

2.4.2 Optimisation analysis

The second function of D-CODE is that it can model the optimised lowest-cost deployment of technologies and programs to meet the future energy needs of an electricity system. The model allows the user to define a scenario that is run through a linear programming model to determine the least cost mix of technologies and programs which would guarantee sufficient future electricity supply. From this scenario, two cases are modelled side-by-side for numerical and graphical comparison – a business-as-usual (BAU) case, and an optimal-mix analysis (OMA) case. Screenshots of the OMA outputs are viewable in the case study below in Section 2.5.

The Optimal Mix case has no restrictions in that it allows the model to select the optimal deployment mix from all inputted technologies. The BAU case, however, restricts the technologies available to centralised fossil fuel and renewable and bioenergy[9] options (to meet the Renewable Energy Target). Furthermore, the BAU case does not consider network costs when determining least cost options, which mimics the current imperfections in the electricity market where network costs do not feature in the private generator investment equation. Network costs are then added post-iteration to compare with the Optimal Mix case.

By comparing these scenarios, D-CODE's OMA shows the comparative benefit of the lowest cost combination of generation technologies (including demand reduction), which satisfies the relevant constraints that apply to the selected jurisdiction, including:

- energy shortfall (in GW per annum)
- peak capacity shortfall (in MW)

[9] The D-CODE model categorises renewable energy and bioenergy separately to provide additional model functionality. The model combines both renewable and bioenergy generation to meet the Renewable Energy Target constraint.

- required renewable energy generating capacity (in GWh p.a., mandated through the Renewable Energy Target legislation).

Jurisdictional energy sector shortfalls from Australian Energy Market Operator demand forecasts (AEMO 2010) were incorporated.[10]

2.4.3 Annualising costs

The D-CODE model annualises (levelised) costs on a per unit basis to enable a fair comparison between projects of varying lifecycles. The cost elements used to calculate the annualised costs are shown in Table 2-2. The upfront costs (which may include capital costs associated with a measure and any incentive or program facilitation costs) are annualised according to the relevant lifespan of the measure, and the weighted average cost of capital (WACC). The lifespans of long-term measures that are unlikely to change in their network availability (such as commercial solar PV or roof insulation) have been capped at 20 years. For behavioural or contract-based measures, short lifespans of around one to three years have been assumed; for measures relating to appliances and equipment, five- to seven-year lifespans have been assumed, and the majority of technology-based measures have assumed lifespans of 10 years. Added to the annualised upfront costs are ongoing costs, such as fixed ongoing costs (in $/kVA/yr) like maintenance or program administration costs, and variable ongoing costs such as fuel costs (in $/MWh). Any variable ongoing costs in $/MWh units are converted into $/kVA by using the annual hours of operation, or the conservation load factor (CLF).[11]

Table 2-2 Calculation of annualised cost of measure ($/kVA/yr)

Annualised cost of measure ($/kVA/yr)	=	**Annualised Upfront cost**	+	**Annual Fixed Ongoing Costs**	+	**Annual Variable Ongoing Costs**
Data required in calculation		• WACC • Lifespan of measure • Upfront cost in $/MW		• Annual fixed ongoing cost		• Variable ongoing cost ($/MWh) • CLF

[10] Further detail on the optimisation function and how the user sets-up and runs it is outlined in the D-CODE User Manual, downloadable from the iGrid website www.igrid.net.au .
[11] The CLF is the factor that relates energy savings in MWH/a to MW peak savings or vice versa.

2.4.4 Cost uptake functions

In order to quantify DM potential for each of the measures, the following ‘potentials’ are often considered:

- technical potential
- economic potential
- achievable potential.

Technical potential can be defined as ‘the whole range of DM, demand response and energy-efficiency technologies available (or are likely to become available) regardless of any regulatory, economic or market barriers‘ (Dunstan et al., 2012). This is applied as the demand reduction ‘impact’ of a given measure (if undertaken by a single customer), and assumes a market uptake of 100%, applied across the relevant end use of a particular sector/sub-sector and region.

Economic potential can be defined as ‘demand reduction that could be brought about if existing technologies/activities were replaced with alternative technologies/activities that are economically viable’ at a particular point in time (Dunstan et al., 2012).

Achievable potential can be defined as ‘economically viable savings resulting from utility and Government interventions/programs or other means, taking into account regulatory, economic and market barriers’ (Dunstan et al., 2012).

However, this conventional ‘technical, economic, achievable’ approach is problematic as it assumes that *achievable potential* is a subset of *economic potential*. This raises three problems.

Firstly, there is the question, when assessing if a measure is economically viable, of whose perspective should be applied – the consumer or the utility/DM provider. If the consumer’s perspective is applied, then that says little about how much potential would be available to be tapped by the DM service provider at any given cost. If the DM provider or utility perspective is applied, then it is unclear how economic potential can be measured. Therefore, the concept of economic potential becomes either irrelevant (in the case of a consumer perspective) or meaningless (in the case of a utility perspective).

Secondly, it is entirely plausible that in some cases, at least from the consumer perspective, that the achievable potential is greater than the economic potential. For example, there is much evidence to suggest that much of the rapid uptake of rooftop solar in recent years in Australia was not cost-effective to the consumers who invested in it. Consumers had other motivations for adopting this measure beyond cost-effectiveness.

Thirdly, and most importantly, from the perspective of the utility or DM provider, the level of cost-effective or achievable potential will vary greatly relative to the avoidable cost of supply. So if a utility has ample spare supply capacity and few if any avoidable costs, the cost-effective or achievable DM potential will be low. On the other hand, if the utility is facing capacity constraints and has high avoidable costs, then the cost-effective or achievable DM potential is likely to be relatively high.

Consequently, in this context, achievable potential is that which is economic to the utility (or other DM service provider) at the given cost. Therefore, for the purposes of the D-CODE model and the cost/uptake function, the concepts of economic and achievable potential have been combined as 'the achievable potential that is economically viable up to the avoidable utility cost in that context'. This has been done because the potential of DM is estimated as what is achievable at a given cost to the utility (or other DM provider). This approach is comparable to the Utility Cost Test discussed in Section 7.3.2.

If we had set the economic cost-effectiveness based on an alternative perspective, such as a societal or customer perspective, this would have removed the capacity of the utility to weigh up DR and network investment on a like-for-like basis. (This 'economically achievable' approach is also analogous to the approach adopted by BC Hydro (Marbek Resource Consultants, 2007), who also defined economic potential as the level of demand reduction achievable up to a specified cost threshold.)

These approaches to reduction potential are related through a **'cost/uptake function'** for each measure, as illustrated in Figure 2-13 below. These functions are constructed through the use of data points characterised using two metrics:

- demand reduction potential from each option as a percentage of the end use within a given context (e.g. a 10% reduction in residential cooling demand in Mackay in 2016)
- annualised cost of the option to the utility (in $/kVA/yr).

Each data point is represented by an ‘x’ in Figure 2-13. These data points are derived from precedent data wherever possible, for example from DM programs implemented. The data used derives from a range of sources, with a particular focus on Queensland data as some of the data was compiled as part of a project for Ergon Energy in Queensland (Dunstan et al., 2012), other Australian jurisdictions, and other countries with similar climate zones and/or electricity using activities to those found in Queensland. In cases where no precedent data was available, a combination of engineering-based calculations and utility costs derived from costs to the customer were computed, as described in Section 2.4.5 below.

Once the data points were determined, a linear curve of best fit was applied to define the cost/uptake function. The function was also made asymptotic to the independently calculated technical potential (represented by the unbroken vertical blue line on the right in Figure 2-13), to ensure that the estimated achievable potential did not exceed the full technical potential even at very high costs. This approach recognises that there is no single efficient cost for any given demand reduction measure, and that the impact or uptake of such a measure is related to how much a utility is willing and able to pay for it. Note that this is considered to be a significant advance in the theoretical approach to utility demand management in Australia.

The different types of instruments that can be used to deliver a measure are recorded and presented on the same cost/uptake function as separate data points. Lower cost instruments that deliver lower uptake (such as the provision of information) populate the bottom-left portion of the cost/uptake function, while higher cost instruments that deliver higher uptake (such as direct installations) populate the upper-right portion of the cost/uptake function. The relative cost-effectiveness of competing instruments is thus plotted on one graph. Some data points were ruled out as anomalous for reasons of inadequate reporting. Other data were excluded from definitions of the cost/uptake function as the data suggested that they did not reflect efficient costs, and other more cost-effective means of delivering the same measure were available.

The lowest level of achievable potential that is economically viable is defined by the intersection (shown by a grey circle) of the cost/uptake function (red line) with the ‘Average Incremental Network Cost’ benchmark, which represents the average marginal cost of installing each kVA of new network capacity. The highest level of achievable potential that is economically viable is defined by the intersection (also shown by a grey circle) of the cost/uptake function with the ‘Growth (DANCE) Avoidable Network Cost’ benchmark, which represents the marginal cost of servicing each kVA of new load growth area (Dunstan et al., 2012).

Note that all costs of measures have been identified from the perspective of the utility, rather than from the perspective of the customer, to compare the delivery of DR with the avoided cost of utility supply. The cost-effectiveness of a measure from the customer's perspective is thus not a direct input to the cost/uptake function. Rather, customer cost-effectiveness is purely a factor that influences the cost or effort that the utility must expend to entice the customer into action.

A highly cost-effective measure will generally require less investment by the utility to entice customers into adopting the measure, and this will be represented as a lower cost to deliver demand reduction in the cost/uptake function for that measure. So, the relative cost-effectiveness of a measure from the customer perspective is not a direct input into the cost/uptake function. However, an understanding of this cost-effectiveness is required to inform the construction of cost/uptake functions where actual utility-delivered precedents are not currently available.

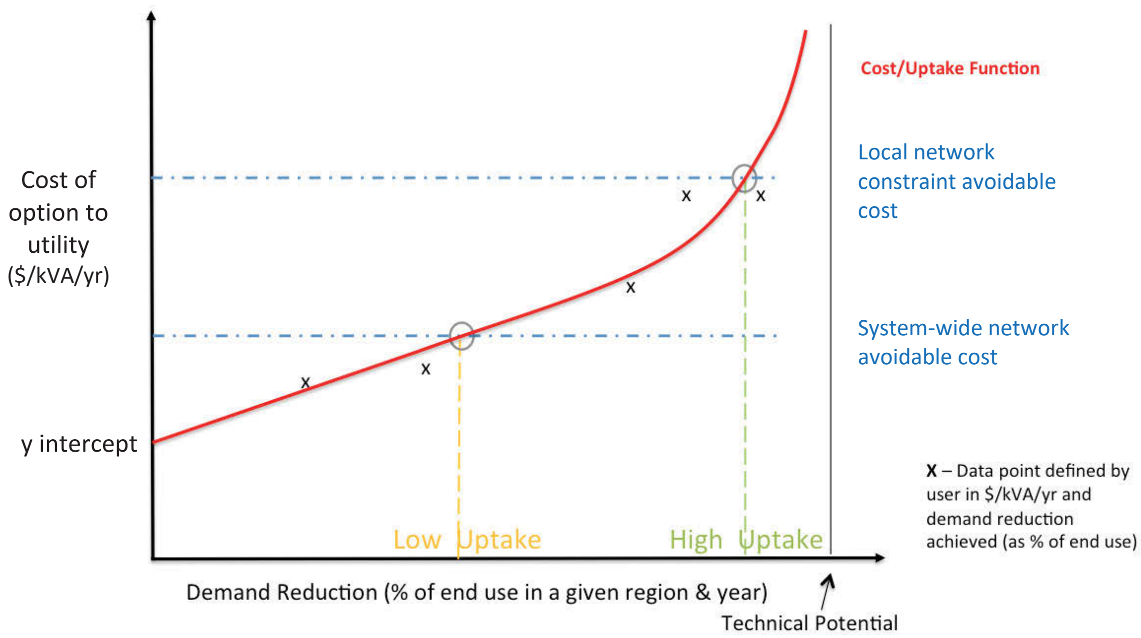


Figure 2-13 Example cost/uptake function

(Dunstan et al. 2012)

Cost/uptake functions are defined for each measure according to the anticipated level of uptake in a given time frame, such as the period to 2025. The time-bound achievable potentials may then be scaled proportionally for intervening years, based on an expected 'deployment curve'. Figure 2-14 illustrates four basic deployment curve shapes that may be applied, using an illustrative timeframe of 2012 to 2025. The shape of the deployment curve depends on the barriers to deployment, the state of technological development, equipment turnover rates and the utility's ability to deliver reductions over time. The four deployment curve shapes and the rationales for their application are:

- **A: Linear** – straight-line deployment over time. This could apply to established technologies and other measures that are constrained mostly by the utility's ability to roll out programs across its territory, or to situations where measures rely on equipment turnover (commercial leasing changeover or air-conditioning replacement rates for example).

- **B: Exponential** – slow initiation, ramping up exponentially over time. This could apply to emerging technologies that are currently limited in their market availability or cost-effectiveness, but become more readily available or less costly over time.

- **C: Inverse exponential** – rapid deployment in earlier years, slowing exponentially by 2025. This could apply to readily available technologies that are currently being deployed but require progressively more effort to deliver their full 2025 potential. An example is standby generation, which is the utilisation of existing generators within the network that require network support contracts (early deployment) or equipment upgrades to provide support (later deployment).

- **D: Early Saturation** – rapid straight-line deployment reaching 2025 potential by approximately 2016. This could apply to readily available technologies that have market momentum but are quickly reaching saturation.

These curves are based on similar curves developed by BC Hydro (Marbek Resource Consultants, 2007) as part of their study of DM potential.

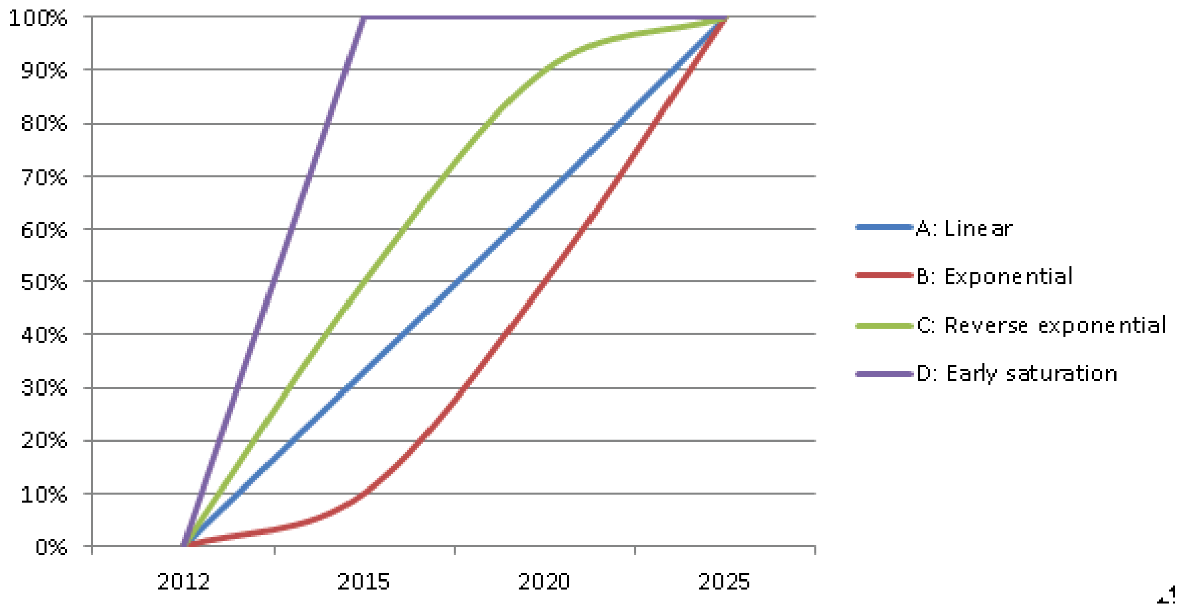


Figure 2-14 Deployment curve types to realise 2025 achievable potential

(Dunstan et al. 2012)

The costs of DE measures in the D-CODE model cost/uptake functions are based on the costs to the DM program provider (such as a utility) to induce end-users to implement particular options, rather than the direct costs to end-users of implementing the options. This is formally equivalent to the Program Administrator Cost Test (PACT) in the least cost planning method as described in Section 7.3.2. This is because the focus of the D-CODE model is on DE as a DM option in the context of least cost planning. Cost effectiveness is just one of many factors that end users take into account in deciding whether to adopt a DE measure. Many DE measures (particularly energy efficiency) ***are not*** adopted despite being cost-effective, and some DE measures, such as customer battery storage, ***are*** adopted despite not being cost-effective.

The cost/uptake function allows a range of DM uptake levels to be considered reflecting different avoidable costs. The calculation of cost/uptake functions is an innovative analytical approach that allows the estimation of different levels of DM potential, depending on the avoidable cost of the supply-side option and therefore how much the utility/DM program manager should be willing to spend. Of course, the robustness of the cost/uptake functions is crucially dependent on the reliability of the data used to estimate the potential level of DE that could be achieved by each option, and the likely level of uptake for the option.

2.4.5 Data limitations

The key difficulty for developing the D-CODE model was the limited availability and consistency of reported data for DE options and projects, from both utility projects and public domain literature. This made the estimation of reliable cost/uptake functions for each DR measure challenging in some cases. Where data gaps are present, assumptions have been made and this increases the level of uncertainty of the results presented.

However, many improvements which increase confidence regarding costs or potential will only become possible when utilities (and other DM program providers) further develop their program evaluation metrics, collect and report data in the appropriate consistent format, and learn from the continued implementation of DM programs. The data-poor nature of this area is one of the primary reasons why the D-CODE model has been established as a publicly accessible tool that users can update and develop using their own assessments of DM potential as their understanding of DM costs, potential, avoidable utility costs and customer demand improves over time.

Measures for which the required data inputs are unavailable or limited have curves built on assumptions based, where possible, on similar measures for which data is available. More detail on data, sources and assumptions for the 33 technologies built into the D-CODE model is recorded in the D-CODE model itself (Dunstan et al., 2011g).

In cases where reliable precedent data on the uptake of measures could not be found, an alternative method was employed to derive a proxy cost/uptake function. Starting at the scale of a single end user (where savings and/or cost data are more accessible) we estimated expected peak savings against the total cost of fully subsidising the measure (lifetime costs plus administration cost faced by utility). The data was then scaled to reflect a roll-out to 90% of eligible end users.[12] Graphically, this is represented by an upper-right data point on the uptake function; that is, a data point very close to the technical potential limit.

In the absence of any other data points to plot an upward sloping uptake curve, a y-intercept (see Figure 2-13) was estimated – that is, the minimum level of subsidy, administration cost or other cost required to stimulate any level of uptake (this is the 'a-coefficient'). This estimate is based on the relative level of both the upfront cost and payback period of that measure. For

[12] Rollout of 90% of technical potential was selected; beyond this, we see rising costs per unit of uptake as willing participants become more difficult to find.

example, a relatively higher upfront cost or a higher payback period implies a higher y intercept. These two estimated data points form the basis of the cost/uptake function and together determine the rate of uptake (the gradient of the line, noted in D-CODE as the 'b-coefficient'). The 'k-coefficient' is then applied as per the other measures to determine the increase in the cost of the measure exponentially as it approaches the technical potential limit (Dunstan et al. 2012).

2.4.6 Limitations of linear functions

The cost-uptake functions develop linear relationships between two or more points of data. This is appropriate where there is limited information across the spectrum from low to high demand reductions and a simple relationship can be established for general application across regions. In certain cases where data is very good, with well-established fixed program costs and customer incentives for different uptake levels, it may be more accurate to define a non-linear relationship. For example, the relationship may start flat or decline before increasing with greater uptake. However, the method applied does not allow inclusion of these more complex relationships between uptake and costs. It is for this reason that the k coefficient has been included to allow the user some additional flexibility to make cost increases more or less steep at lower uptake levels before the technical potential is reached. With more data, cost uptake functions could easily be resolved into quadratic or other polynomial equation forms.

2.4.7 Interactions between measures

Multiple measures do not necessarily have a fully additive effect when implemented together, as they may overlap in their applications. This is particularly true where two measures influence the same end use in the same sector. For example, installing insulation in the home would reduce the potential DM achievable from installing a more efficient air conditioner. The combined potential presented in this D-CODE model considers these interactions in order to prevent double counting, through a 'discounting' function. As different measures have different costs, it is assumed that the measures will be implemented in lowest to highest cost order. In this way, the measure with the lowest starting price will be assigned the full reduction potential. The next measure will have the discount applied for its cost/uptake function.

For example, if a hot water loss reduction measure reduces peak hot water (HW) demand by 10%, while an HW conversion from electric resistance to an electric heat pump reduces demand by 30%, these measures would interact. If loss reduction was cheaper, the full 10% reduction would apply. The impact of the HW conversion would assume a 10% lower HW end use, meaning that effectively a reduction of only 30% x 0.9 = 27% would be attributed to this measure.

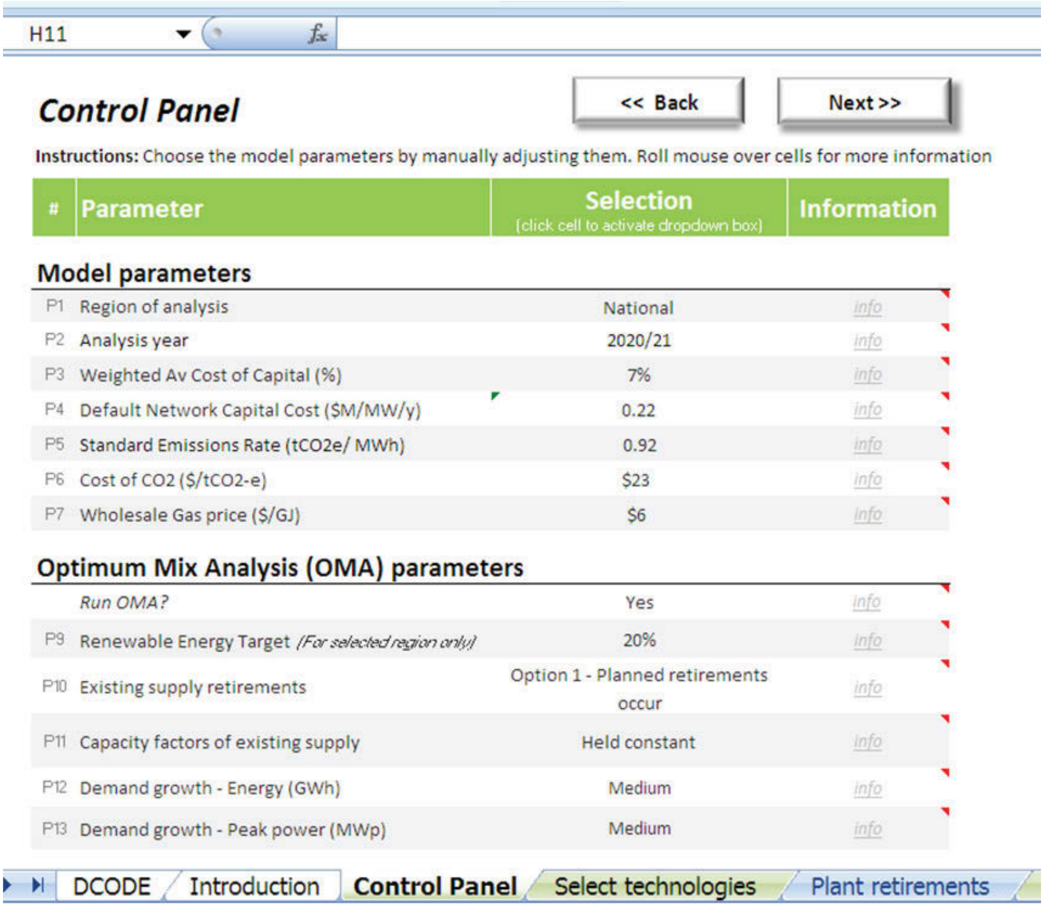
2.5 D-CODE case study 1: Australia 2020

The D-CODE findings highlight the large cost disparity between DE options that avoid the need for network infrastructure, and the continued expansion of centralised generation capacity and network infrastructure. D-CODE presents these findings in a straightforward, powerful manner that clearly demonstrates that a shift away from an exclusive focus on centralised generation to a more decentralised and balanced supply- and demand-side strategy could save electricity consumers billions of dollars and substantially reduce greenhouse gas emissions.

To demonstrate the potential of the D-CODE model, the case study below was constructed to represent current market conditions in Australia in 2011, to investigate the costs and opportunities deliverable through decentralised energy over a 10-year planning horizon out to 2020-21.

2.5.1 Inputs

To represent current market conditions, the 'control panel' was set up as shown in Figure 2-15, with a default $23 carbon price (which was the anticipated regulated price in Australia at that time), network costs reflective of current investment, and a 20% Renewable Energy Target. All these settings are adjustable by the user.



H11

Control Panel

<< Back | Next >>

Instructions: Choose the model parameters by manually adjusting them. Roll mouse over cells for more information

#	Parameter	Selection (click cell to activate dropdown box)	Information
	Model parameters		
P1	Region of analysis	National	info
P2	Analysis year	2020/21	info
P3	Weighted Av Cost of Capital (%)	7%	info
P4	Default Network Capital Cost ($M/MW/y)	0.22	info
P5	Standard Emissions Rate (tCO2e/ MWh)	0.92	info
P6	Cost of CO2 ($/tCO2-e)	$23	info
P7	Wholesale Gas price ($/GJ)	$6	info
	Optimum Mix Analysis (OMA) parameters		
	Run OMA?	Yes	info
P9	Renewable Energy Target *(For selected region only)*	20%	info
P10	Existing supply retirements	Option 1 - Planned retirements occur	info
P11	Capacity factors of existing supply	Held constant	info
P12	Demand growth - Energy (GWh)	Medium	info
P13	Demand growth - Peak power (MWp)	Medium	info

DCODE | Introduction | **Control Panel** | Select technologies | Plant retirements

Figure 2-15 Market parameters selected in case study
(Dunstan et al. 2011c)

2.5.2 Modelled energy sector constraints

Based on the selected market parameters, the following constraint levels are specified by D-CODE. Based on 2011 data, in 2020, there was a forecast peak capacity shortfall of 8,939 MW and an annual energy shortfall of 39,594 GWh (with the option selected to prevent the operation of existing fossil fuel supply capacity from being increased to cover the energy shortfall). The renewable energy target means that an additional 30,600 GWh of renewable energy generation would be required in 2020.

Table 2-3 below contains the constraint levels and the modelled constraint values. As can be seen, the Optimal Mix case has a lower level of renewable energy deployment than is actually specified by the target in GWh per annum terms. This is due to the reduced system annual energy generation (as a result of deployed demand management opportunities) leading to a lower amount of required renewable generation to achieve a 20% penetration.

Table 2-3 Case study constraint levels and modelled values (annual values)

Constraints	BAU	Optimal Mix (DE)
Constraint #1 applied: Peak capacity shortfall (new capacity required, MWp)	8,939	8,939
Modelled new peak capacity MWp (incl. demand reduction)	8,939	8,939
Constraint #2 applied: Energy generation shortfall, GWh	39,594	39,594
Modelled new generation (or demand reduction), GWh	39,594	46,047
Constraint #3 applied: Renewable energy target, GWh	30,600	30,600
Modelled renewable energy deployed, GWh (where lower than renewable energy target, this is due to reduction in demand compared to forecasts)	30,600	26,759

(Dunstan et al. 2011c)

2.5.3 Outputs

The numerical outputs are displayed in Table 2-4 below and graphical outputs are displayed in Figure 2-16, Figure 2-17 and 2-18 for business as usual and Figures 2-19, Figure 2-20 and Figure 2-21 for Optimal Mix.

Table 2-4 2020-21 Case study results: Optimal Mix case versus business as usual (BAU) case

		Business as usual	Optimal Mix (DE)
Costs	Annualised total cost ($billions 2010)	6.65	3.77
	Annualised total capital costs	3.10	2.64
	Annualised total fuel and operation costs	0.48	0.41
	Annualised total network costs	2.97	1.00
	Annualised total carbon costs	0.10	0.01
	Variable fuel O&M cost (avoided) from displacing existing generation	0.00	-0.14
	Carbon cost (avoided) from displacing existing generation	0.00	-0.15
Peak demand/supply	Peak demand MWp, analysis year		
	BAU peak demand MWp	61,925	61,925
	Peak demand reduction from BAU MWp	0	-6,352
	Total system peak demand MWp	61,925	55,574
	Percentage reduction in peak demand from BAU	0.0%	-10.3%
	Peak supply MWp, Analysis year		
	2011 peak capacity of existing generators, MWp	52,434	52,434
	Change in peak capacity, between 2011 and 2020, MWp	552	552
	Total peak capacity of existing generators, 2020 MWp	52,986	52,986
	Modelled additional peak capacity, MWp	**8,939**	**2,587**
	Total system peak supply, MWp	**61,925**	**55,574**
	Percentage increase in peak supply, MWp	16.9%	4.9%
Annual Energy demand/supply	Annual Energy demand GWh		
	BAU 2020 energy demand GWh	279,700	279,700
	Energy demand reduction GWh	0	**-19,204**
	Total system energy demand GWh	279,700	260,496
	Percentage reduction in energy demand from BAU	0.0%	-6.9%
	Annual energy supply GWh		
	2011 generation of existing generators, GWh	237,822	237,822
	Change in generation potential, between 2011 and 2020, GWh	2,285	2,285
	Total potential provided by existing capacity, 2020, GWh	240,106	240,106
	Total required supply from existing generators, 2020, GWh	240,106	233,737
	Modelled additional supply-side generation, GWh	**39,594**	**26,759**
	Total annual energy supply GWh	279,700	260,496
Emissions	Emissions of added generation $MtCO_2$	4.32	0.40
	Emissions of existing generation $MtCO_2$	222.37	215.90
	Total emissions, $MtCO_2$	**226.69**	**216.29**
	Standard emissions rate, $kgCO_2$/KWh	0.81	0.83
	Compared to BAU, analysis year	0.0%	-4.6%
	Compared to 2010 (forecast) emissions	9.6%	4.6%
	Compared to 1990 emissions	75.1%	67.1%

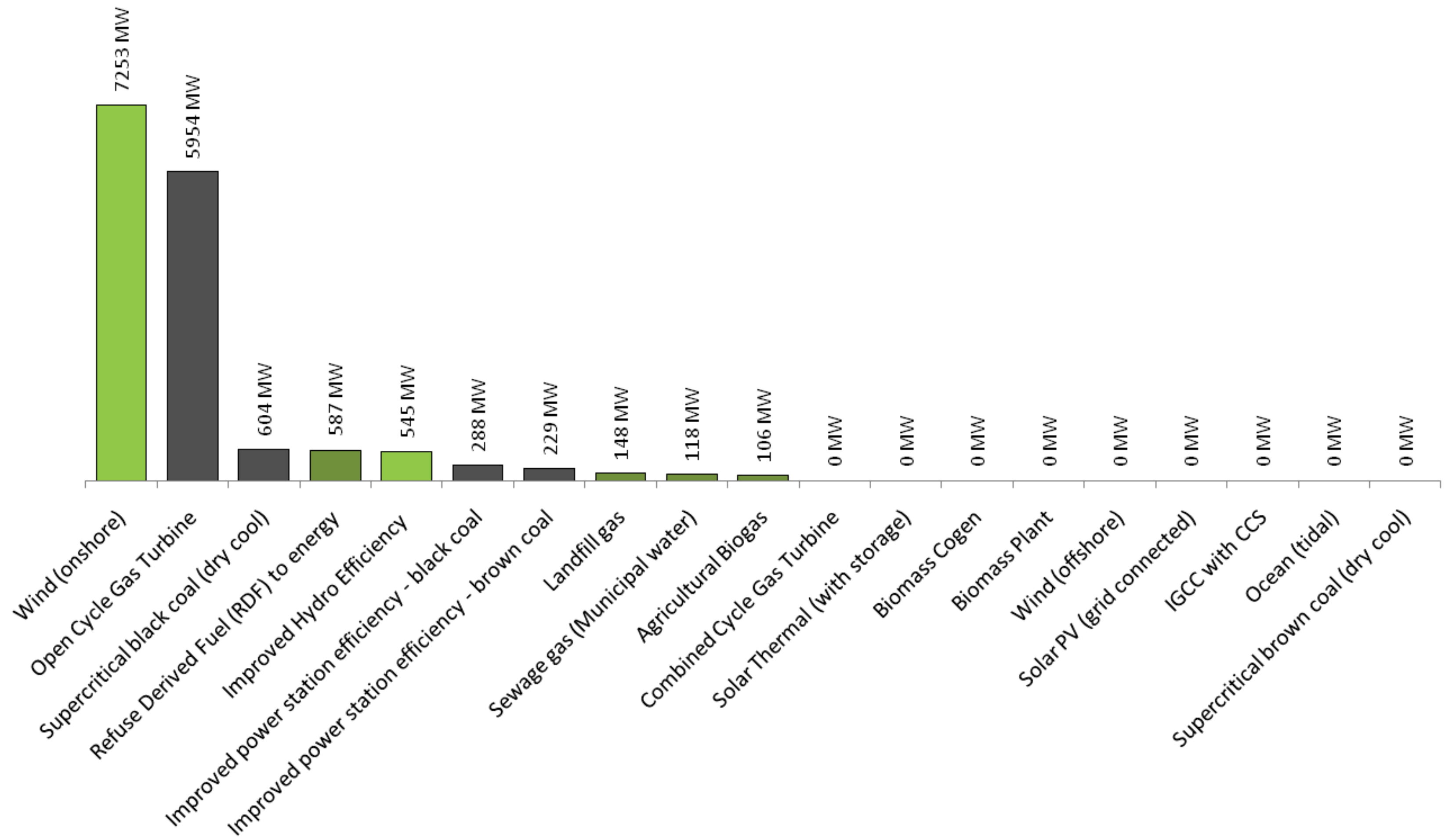
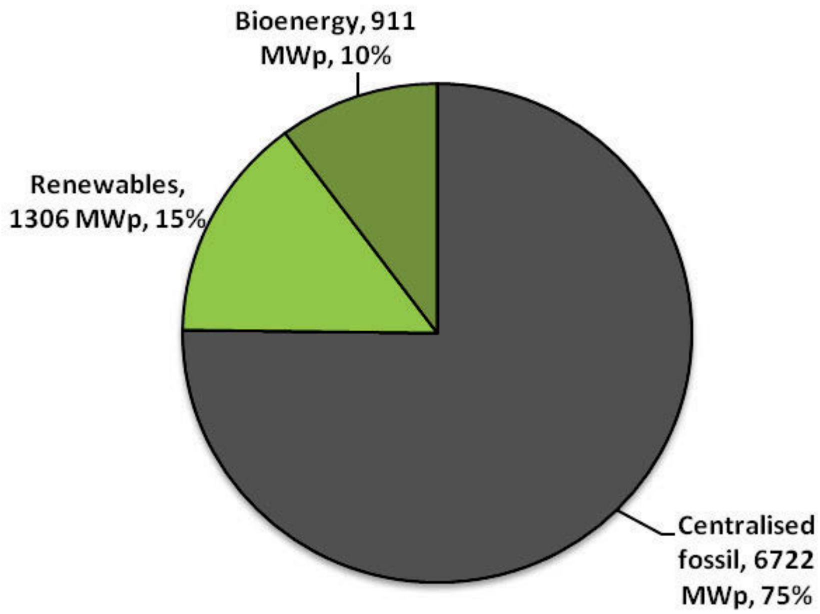


Figure 2-16 BAU case, deployed technologies to meet energy and peak capacity shortfalls

(Dunstan et al. 2011c)



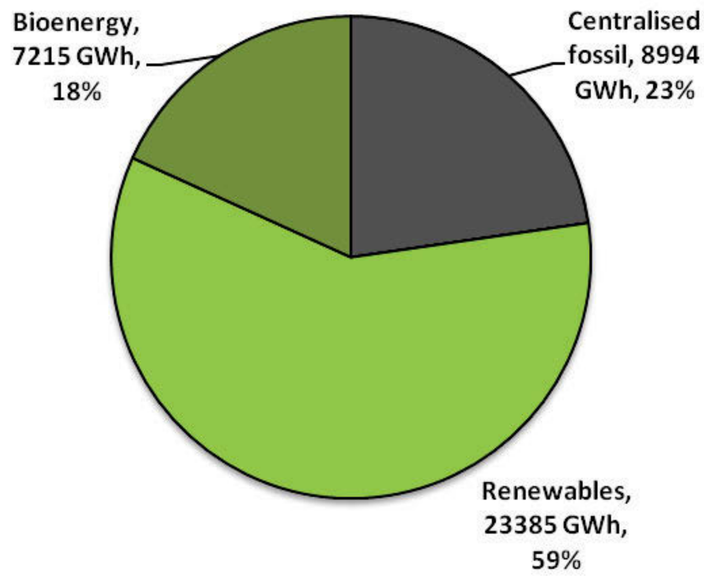


Figure 2-17 BAU case, new *peak capacity* (to meet 2020-21 shortfall)

(Dunstan et al. 2011c)

Figure 2-18 BAU case, new *energy generation* (to meet RET & 2020-21 shortfall)

(Dunstan et al. 2011c)

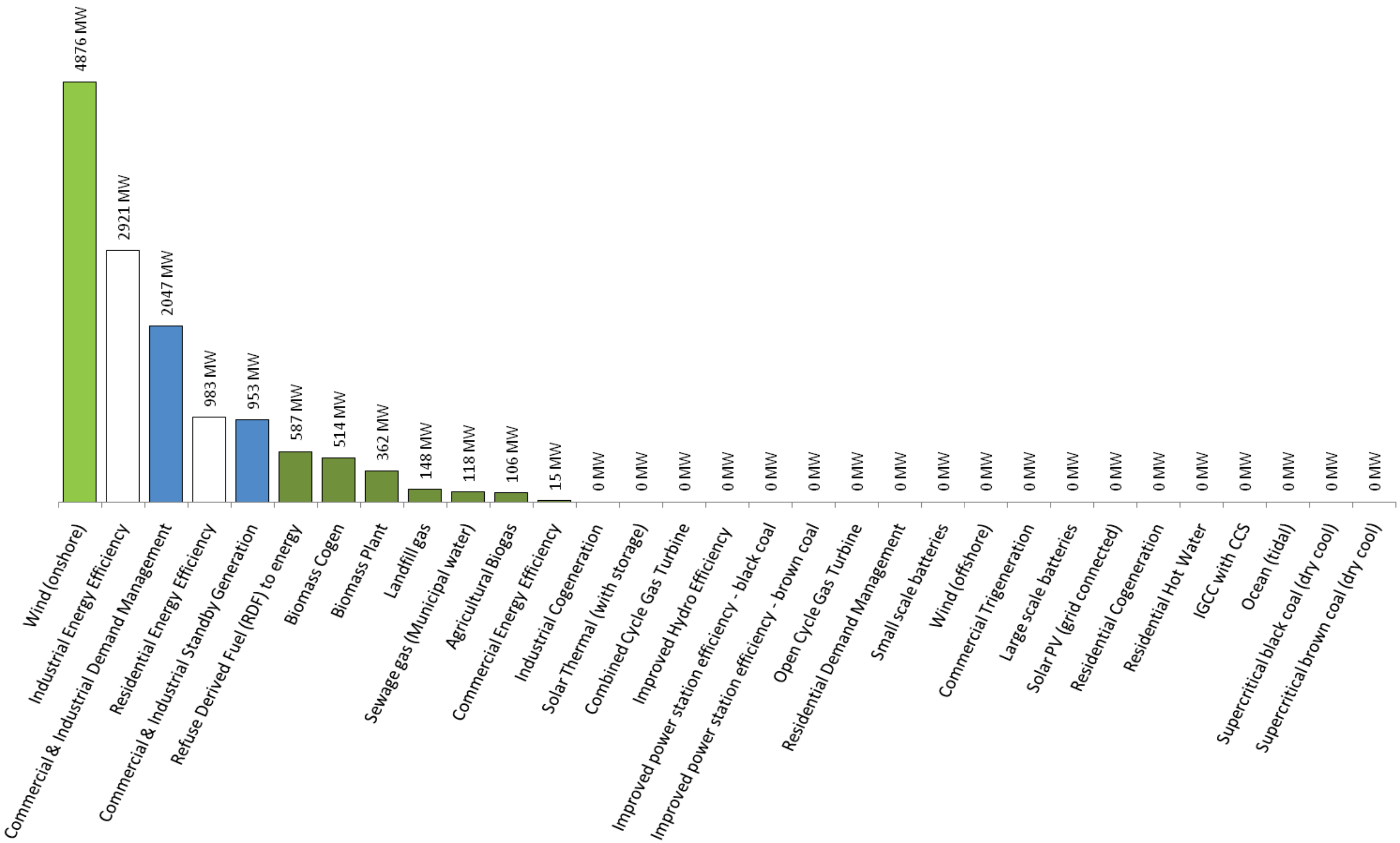


Figure 2-19 Optimal Mix case, technology mix to meet energy and peak capacity shortfalls

(Dunstan et al. 2011c)

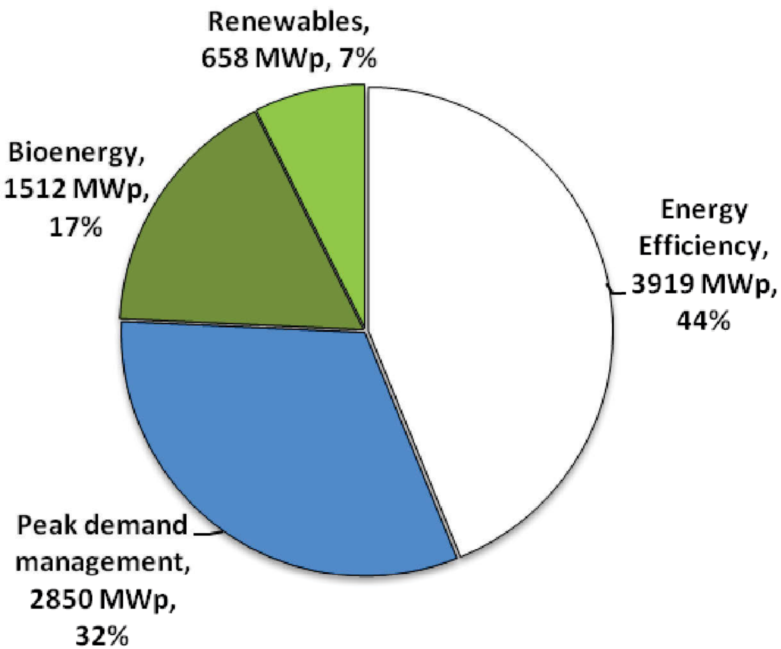


Figure 2-20 Optimal Mix case, new *peak capacity* (2020-21 shortfall)

(Dunstan et al. 2011c)

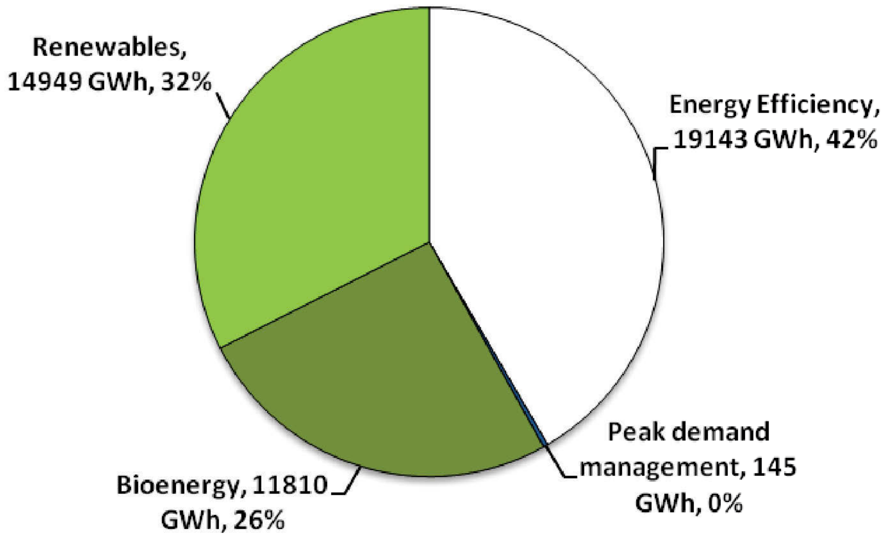


Figure 2-21 Optimal Mix case, new *energy generation* (RET & 2020-21 shortfall)

(Dunstan et al. 2011c)

2.5.4 Discussion of modelling results

Deployed technologies

To meet Australia's 2020–21 electricity demand under the medium growth scenario, the **Business as Usual** (BAU) case strongly deploys fossil fuels, combined with renewable and bioenergy (see Figure 2-16, Figure 2-17 and Figure 2-18). In this case, in order to meet the Renewable Energy Target (RET), 7,253 MW of wind generation is deployed alongside some cheaper bioenergy, and these technologies go most of the way to meeting the energy constraints. However, as wind has a low firm peak rating, there is still a large peak supply shortfall, meaning that 5,954 MW of peaking open cycle gas-fired generation is deployed, combined with 604 MW of additional black coal capacity to ensure reliable baseload and peak supply. Approximately 517 MW of capacity was gained by improving the efficiency of existing black coal and brown coal-fired power stations.

In the **Optimal Mix case** (see Figure 2-19, Figure 2-20 and Figure 2-21), taking account of network connection costs mean only 4,876MW of new wind generation is deployed (2,377 MW less than in the BAU case). The reduced wind capacity, and reduced hydroelectricity is replaced by a range of bioenergy technologies which increase to 1,835 MW of capacity (see Figure 2-19), and contribute 1,512 MWp at the time of peak demand (see Figure 2-20). The remaining peak capacity and energy requirements above what is 'forced' by the RET are met purely by DE options such as industrial, commercial and residential energy efficiency, commercial and industrial demand management, and a small amount of commercial and industrial standby generation. These DE options also provide sufficient energy to meet the energy generation shortfall, resulting in significant cost savings from avoided fossil fuel generation.

Costs

As shown in Table 2-4, the total cost of deployed technologies is much lower in the Optimal Mix case than it is in the BAU case. Overall, costs to meet Australia's electricity needs to 2020–21 are $2.9 billion per year lower in the Optimal Mix case where DE options are strongly deployed, representing a 43% cost saving compared to BAU. Of particular note are network costs, which comprise almost $2 billion of the $2.9 billion savings. The capital, variable fuel and operation costs, and the carbon costs of the Optimal Mix case are also lower than in the BAU case.

Supply/demand balance

In the Optimal Mix case, demand reduction from DE reduces expected 2020 peak demand by 10.3%, from 61,925 MWp to 55,574 MWp. Expected 2020 annual energy supply is reduced by 6.9%, from 279,700 GWh per annum in BAU to 260,496 GWh per annum in the Optimal Mix case. As a reference, 2011 demand figures were 47,062 MWp at the peak and 224,824 GWh per annum.

Emissions

Emissions from the additional deployed technology options are 0.4 $MtCO_2$-e per annum in the Optimal Mix case, compared to 4.3 $MtCO_2$-e per annum in the BAU case – an emissions saving of 3.9 $MtCO_2$-e per annum (see Table 2-4). An additional 6.5 $MtCO_2$-e per annum of emission reduction comes from greater displacement of existing fossil fuel generation with lower-cost demand-side options. This 10.4 $MtCO_2$-e per annum saving equates to 4.6% lower total electricity sector emissions in the Optimal Mix case compared to BAU. The reason the disparity is not even greater is that most of the energy generation shortfall in both cases was met through renewable energy in order to meet the Renewable Energy Target, and most of the remaining investment in the BAU case was in open cycle gas turbines, an option which – as a peak period generator only – runs infrequently. For Australia to further reduce its electricity emissions it would need to retire existing coal-fired generators. This is not unrealistic, as many coal-fired generators have already reached, or are approaching, their anticipated retirement ages. (Indeed, as discussed in section 1.3.1, in the six year period since this analysis was undertaken, ten coal-fired power stations have already shut down.)

To demonstrate this point, a third "Coal Retirement" case of the model was run, in which it was found that Australia could shut down 7,000 MW of coal fired power and replace it primarily with DE to achieve a 16% reduction in total electricity sector emissions. Remarkably, doing so would present a 5% or $360 million per year cost saving compared to the BAU case. This result is achievable via a combination of energy efficiency, peak demand management, cogeneration, renewable/bioenergy and combined cycle natural gas (Dunstan et al., 2011c, pp. 24-25).

2.5.5 Case study summary

The D-CODE model outputs for Australia's 10-year energy sector planning horizon clearly demonstrate the significant potential benefits of implementing widespread DE, both in terms of reduced costs and reduced greenhouse gas emissions. The $2.9 billion per year saving derived predominantly from the avoidance of large-scale investment in network augmentation. The focus on DE saves 4.5% from total electricity sector emissions, while delivering these reductions at a net *benefit* to electricity consumers. In the Coal Retirement case, retiring 7000MW of existing coal generation would reduce electricity sector emissions by 16%, with a 5% cost saving compared to Business as Usual.

D-CODE was used to compare two cases side-by-side. One case simulated how current Australian electricity markets act, with imperfections and bias in favour of existing centralised supply-side solutions to future energy demands. The other simulated an environment where institutional barriers to DE are removed and the economic potential of these technologies and practices can be realised. In doing so, D-CODE presents a clear and compelling case for the removal of institutional barriers to DE, to unlock investment in lowest-cost, lowest-emission electricity options.

The D-CODE model has been developed in response to the lack of information needed to compare the costs and benefits of different ‘decentralised energy’ opportunities. By including network infrastructure costs in the equation, it is possible to compare the ‘full cost impact’ of a range of different technology options for meeting our electricity needs, be it using supply- or demand-side approaches. D-CODE has been designed with the user in mind, based on principles of simplicity, transparency and versatility. The outputs clearly demonstrate the potential for DE to satisfy a large proportion of Australia’s future electricity needs with lower emissions and costs than the status quo of expanding centralised generation and associated electricity networks. The outputs also highlight the costly inefficiency in the current electricity market.

2.6 Other applications of the D-CODE model

Since 2008, my colleagues at the Institute for Sustainable Futures (ISF) and I have used versions of the D-CODE model and related approaches to analyse scenarios and case studies in terms of cost and emissions abatement for clients including Victorian and NSW government departments, CSIRO, electricity utilities, non-government organisations and local councils.

The following provides a brief summary of three of these applications:

- Decentralised Energy Costs and Opportunities for Victoria
- Towards 100% Renewable Energy for Kangaroo Island
- Beyond Coal: Alternatives to Extending Liddell Power Station

2.6.1 Decentralised energy costs and opportunities for Victoria

In 2011, the Victorian Government commissioned ISF to assess the potential opportunities, costs and benefits for Decentralised Energy in Victoria, particularly in the context of reducing electricity network investment (Langham et al. 2011b).

This project, which I directed, found substantial untapped cost-effective potential for DE, which could save Victorian electricity consumers $437 million per annum by 2020 relative to business as usual (BAU). It is estimated that this saving would result in reductions in average consumer electricity bills of 4.7%. More than half of these savings was due to reduced expenditure on electricity networks. The remainder was attributable to lower fuel and operational costs associated with DE technologies (particularly energy efficiency and demand response), and reduced carbon emissions liability.

This Decentralised Energy scenario also led to emissions reductions of 3.3 Mt CO_2 per annum (a 6 per cent reduction compared to 2020 BAU electricity emissions), at a *net benefit* of $110 for every tonne of CO_2 abated.

The study also assessed a third scenario based on the early retirement of 1600MW of coal fired generation, equivalent to Hazelwood Power Station, Victoria's oldest and most carbon polluting power station. The relative annual costs of the three scenarios are shown in Figure 2-22.

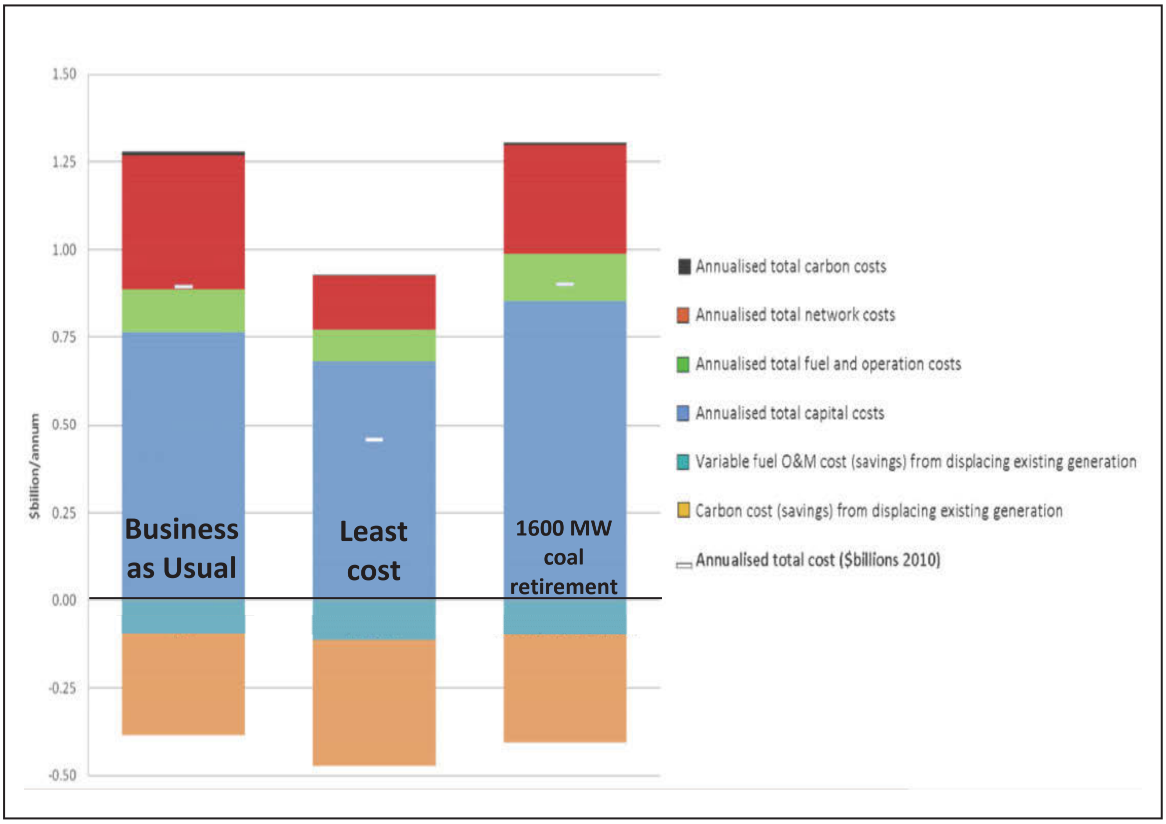


Figure 2-22 Relative annual cost of meeting Victorian electricity needs in 2020

(Langham et al., 2011b, p.17)

2.6.2 Towards 100% Renewable Energy for Kangaroo Island

Kangaroo Island's electricity is currently supplied through a 15 km submarine cable from mainland South Australia. As this cable is approaching the end of its design life, SA Power Networks (SAPN), the local electricity distribution network business, was investigating options for future electricity supply for the island. The preferred network option was a replacement submarine cable at an estimated capital cost of between $22 and $50 million (SAPN, 2016). ISF was commissioned by the Australian Renewable Energy Agency, with support from Kangaroo Island Council and the Kangaroo Island Commissioner, to investigate alternatives to replacing the cable.

The study, which I led, *Towards 100% Renewable Energy for Kangaroo Island*, assessed decentralised energy options for reliable local power supply to meet Kangaroo Island's electricity needs from resources on the island, while delivering power reliability that is equivalent to or better than would be provided by the new cable option. The local power supply would be largely based on renewable energy sources including a mix of wind, solar and biomass, supported by batteries, demand management and back-up diesel generation. This study also considered how local supply options could allow Kangaroo Island to transition towards 100% renewable power.

This study considered ten possible scenarios, based on publicly available data, for meeting the electricity needs of Kangaroo Island over a 25-year time horizon. A reliable, local '**Wind-Solar-Diesel Hybrid'** Scenario was found to be comparable in cost to the **New Cable** Scenario.

The third main scenario considered was the **Balanced 100% Renewables** Scenario which would use Kangaroo Island's unused timber plantations to fuel biomass electricity generation to complement the wind and solar resources in the Wind-Solar-Diesel Hybrid Scenario. The biomass generation would largely displace imported diesel fuel generation.

The Balanced 100% Renewables Scenario was estimated to cost about 15% more in direct costs than the Wind-Solar-Diesel Hybrid Scenario, ($100 million versus $87 million) or $7 million more including indirect costs). The cost of the three scenarios are summarised in Table 2-5 and Figure 2-23.

Table 2-5 Estimated costs of new cable and local power supplies scenarios (Dunstan et al, 2016)

Scenario	New Cable	Wind-Solar-Diesel Hybrid	Balanced 100% Renewables
Direct costs (NPV)	**$77 million**	**$87 million**	**$100 million**
Capital expenditure (amortised)	$34 million[13]	$60 million	$87 million
Operating expenditure	$43 million	$42 million	$29 million
(less Renewable Energy Certificates)	0	(-$15 million)	(-$16 million)
Range of direct costs	$57-96 million	$70-102 million	$69-129 million
Direct & indirect costs	**$169 million**	**$159 million**	**$166 million**
Range of direct & indirect costs	$141-198 million	$119-184 million	$113-204 million

[13] The cable capital cost is $36 million, the centre of the range of uncertainty in SAPN's Non-network Options Report, amortised over a 35-year anticipated lifetime, and (as with all costs) is expressed as a net present cost over 25 years.

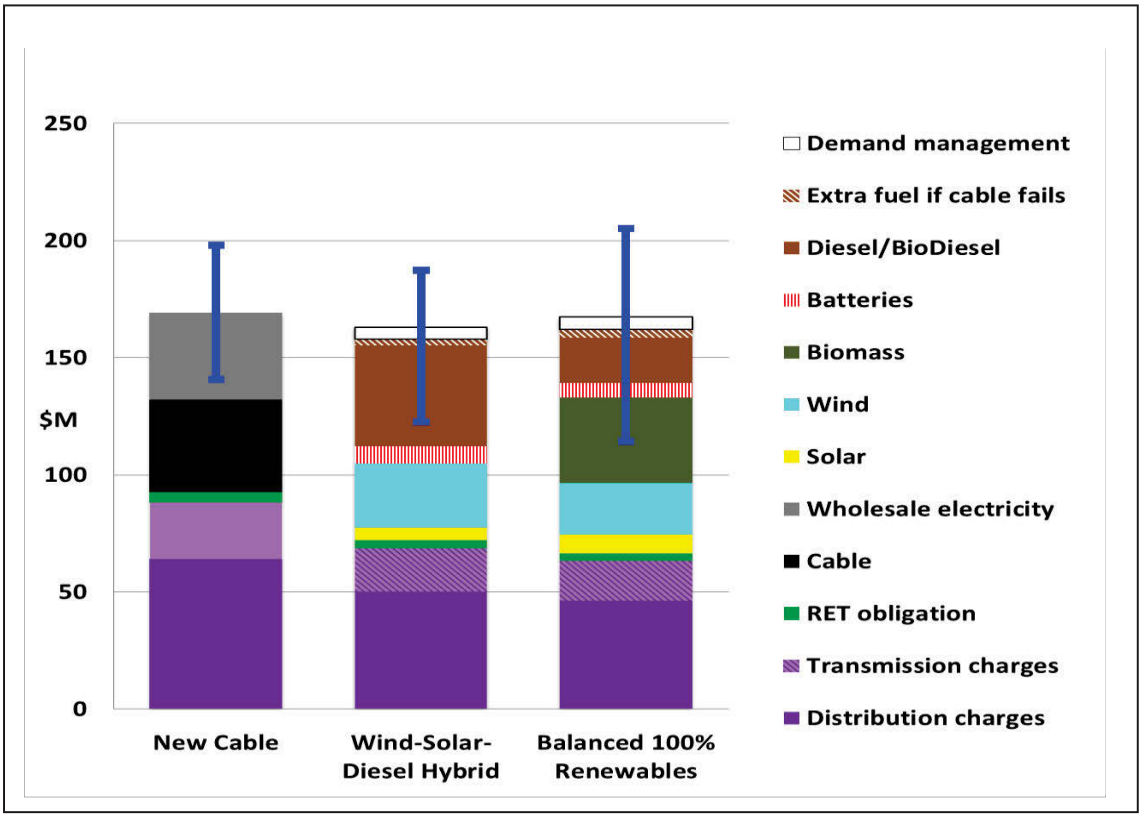


Figure 2-23 Direct and indirect costs of new cable and local power scenarios
(Dunstan et al, 2016, p. 7)
(Net present value over 25 years; Vertical blue bar indicates range of uncertainty)

2.6.3 Beyond Coal: Alternatives to Extending Liddell Power Station

In 2017, the Australian Energy Market Operator (AEMO) raised the prospect of a shortfall in electricity supply in the summer of 2023/24 following the scheduled closure of the Liddell Power Station in the Hunter Valley, NSW in 2022. In response, the Australian Government suggested that the best way to avoid any supply disruption was to defer the scheduled closure of Liddell for at least five years. In contrast, AGL, the owner of the power station, proposed managing the transition through a mix of new gas-fired and renewable generation, batteries and demand response.

The Australian Conservation Foundation commissioned ISF to undertake a study (which I led), *Beyond Coal: Alternatives to Extending the Life of Liddell Power Station* to inform this debate by investigating alternatives to both the Commonwealth Government and AGL proposals. To this end, the study illustrates and compares three different primary scenarios: extending Liddell's operations; AGL's proposal and a "clean energy package".

Our modelling found that the Clean Energy Package would save more than $1.3 billion compared to the Extend Liddell scenario and more than $1 billion compared to the AGL Proposal. The total cost (including capital and operating costs) for five years is estimated at $2.2 billion for the Clean Energy Package, compared to $3.6 billion for the Extend Liddell proposal and $3.3 billion for the AGL Proposal. Furthermore, the Clean Energy package would have zero carbon emissions compared to 40 million tonnes of carbon dioxide over five years in the case of the Extend Liddell proposal and 2.5 million tonnes of carbon dioxide for the AGL scenario.

The results of the capacity and energy case are summarised in the infographic shown in Figure 2-24.

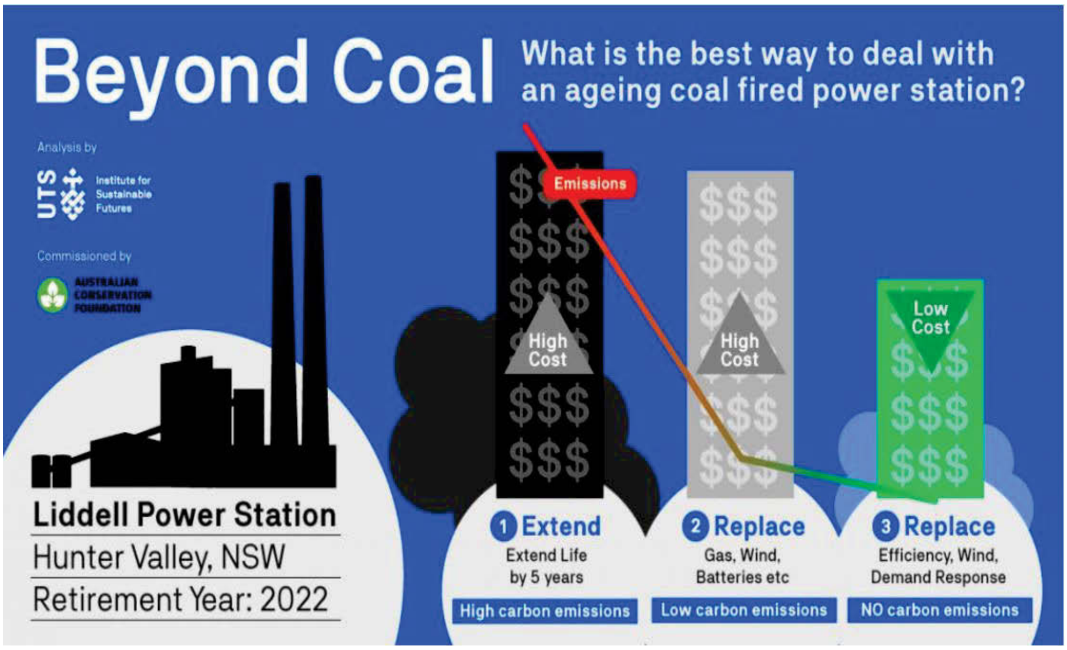


Figure 2-24 Cost and carbon emissions comparisons across scenarios (Dunstan et al. 2017)

2.7 Summary and implications

By developing and applying a novel modelling tool (D-CODE) for assessing decentralised energy relative to centralised supply, this chapter has presented abundant evidence that greater uptake of decentralised energy has the potential to deliver large cost reductions and emissions savings. This analysis accords with numerous previous studies undertaken in Australia and overseas. However, the analysis in this chapter has highlighted that if the analysis is undertaken at a more disaggregated level, taking account of the potential avoidable costs in electricity network system, then the extent of potential savings is likely to be much greater. This underlines the need for a much clearer and finer grained understanding of network costs and how these relate to decentralised energy technologies and the practice of DM, particularly network DM.

Chapters 3 and 4 examine these two issues.

Chapter 3. Assessing the Status of Network Demand Management

3.1 Introduction

One reason for the stop-start nature of DM development in Australia over the past 80 years is that there has never been a comprehensive and consistent approach to measuring and reporting the performance of DM initiatives and the potential of DM to meet consumers' needs. By contrast, the scale and contribution of electricity supply technologies has been comprehensively recognised and reported for many decades, both by the industry, for example in the annual *Electricity Gas Australia* publication which was produced for many decades by the Energy Supply Association of Australia (ESAA 2005[14]) and by government, for example in the annual 'Australian energy update'[15] (Dept. of Industry, Innovation and Science 2016).

This absence of measuring and reporting of DM performance has obscured the impact and value of DM, made it more difficult for utilities to learn from each other, and impeded the capacity of regulators and policy makers both to recognise the importance of DM and to design appropriate incentives to support DM activity.

While there have been some efforts to estimate the scale of DM in the retail electricity market, network DM has been neglected. As part of the research for this thesis, I identified the absence of measurement and reporting of network DM as a significant gap in knowledge in the electricity sector. I therefore developed and led the first comprehensive survey of network DM in Australia. In order to resource this research, I approached the Australian Alliance to Save Energy (A2SE)[16] to support the survey. A2SE agreed to incorporate the Survey of Electricity Network Demand Management in Australia (SENDMA) into a broader study it was planning to carry out on the role of energy efficiency and demand management in energy network planning (Dunstan, Ghiotto & Ross 2011). This broader program also incorporated the survey of perceived barriers to DM discussed in Chapter 5.

I then collaborated with A2SE in order to secure funding from several state and federal government agencies (see below). The SENDMA report aimed to create, as far as practically possible, a nationally consistent and comprehensive picture of the level of investment in, and

[14] For example, Energy Supply Association of Australia (ESAA) 2005, *Electricity Gas Australia 2015*, Melbourne.
[15] For example, Australian Energy Update 2016
[16] Subsequent to carrying out this survey in 2011, I took on the role of part time Chief Executive of the A2SE.

effectiveness of, DM activity by Australian electricity network businesses. It was anticipated that this information would be valuable for electricity customers, DM service providers, policy makers and electricity network businesses themselves. The survey was the first such comprehensive assessment of electricity network DM in Australia and it is a key contribution to new knowledge that emerges from my doctoral research.

This chapter covers the method and results of this research. The SENDMA provides an estimate of the peak demand reduction delivered by network business DM programs in Australia. In order to place in context the DM undertaken by the network businesses, I have also estimated electricity market DM delivered by electricity retailers. The AEMO Statement of Opportunities report for the corresponding period outlines these electricity market DM initiatives (AEMO, 2011). In addition, I have added an estimate of the contribution of state-based programs primarily targeted at energy efficiency. These programs include the NSW Energy Savings Scheme (ESS), the South Australian Residential Energy Efficiency Scheme (REES) and the Victorian Energy Efficiency Target (VEET). As the direct contribution of these programs to peak demand reduction is not reported, I have assumed that their demand reduction impacts are spread evenly across each 24-hour period.

The aggregate peak demand reduction from network DM and energy market DM and state-based energy efficiency schemes in the NEM is shown in Table 3-1. This ranges from just under one per cent of peak demand in 2008/09 to just over two per cent in 2010/11. It should be noted that the 2010/11 estimate for network DM is based on forecasts by the network businesses in the SENDMA, and therefore may not have eventuated in practice.

It is a strong conclusion of this thesis that consistent, nationwide, annual measurement and reporting of network DM should be introduced (see Recommendation N21 in section 9.3). This should be complemented with equivalent measurement and reporting on energy market DM.

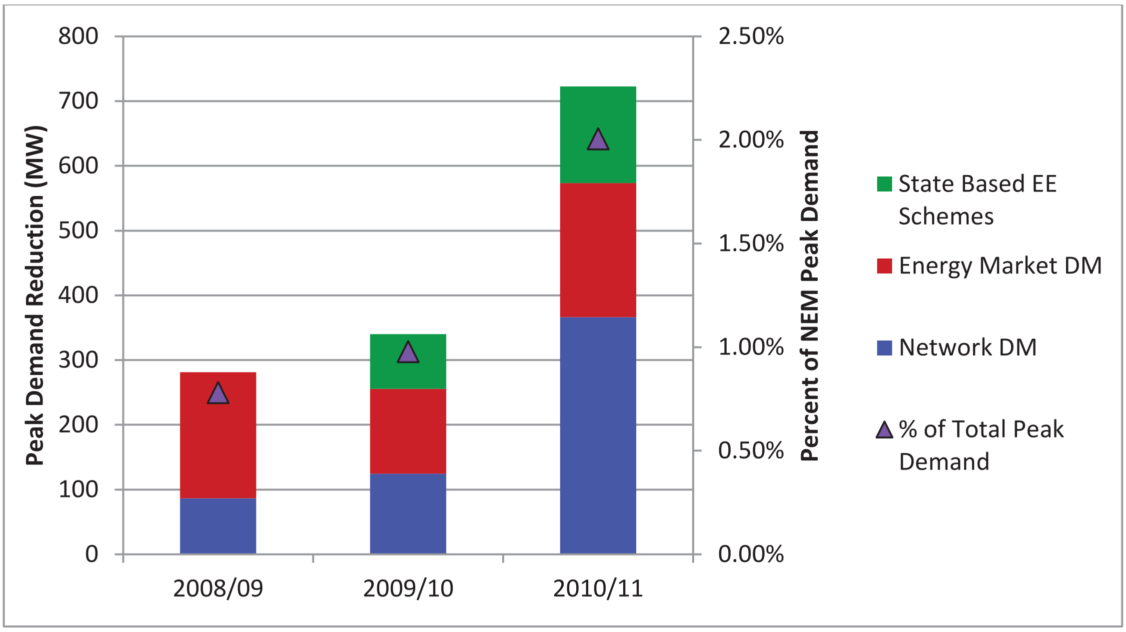


Figure 3-1 Peak demand reduction from network and energy market DM

(Dunstan et al., 2011d)

Table 3-1 NEM total demand management

Year	Peak Demand Reduction (MW)
2008/09	281
2009/10	340
2010/11 (forecast)	723

(Dunstan et al., 2011d)

In contrast to Australia, the United States has undertaken consistent, annual, nationwide reporting on DM programs since the 1980s via the Energy Information Administration in their report, the 'Electric Power Annual Report' (Energy Information Administration, 2011, p.233), as illustrated in Table 3.2

Table 3-2 US electricity sector demand management

Year	Peak load reduction (MW)*[17]	Total peak demand (MW)	DM (% of total peak demand)
2007	30,253	782,227	3.81%
2008	31,735	752,470	4.15%
2009	31,682	725,958	4.29%
2010	33,283	767,948	4.26%

(US Energy Information Administration, 2011, p.233)

Data for earlier periods is shown in Figure 3-2 with demand reductions due to peak load management programs shown in comparison to energy efficiency programs. No comparable data exists for demand management performance in Australia prior to 2008.

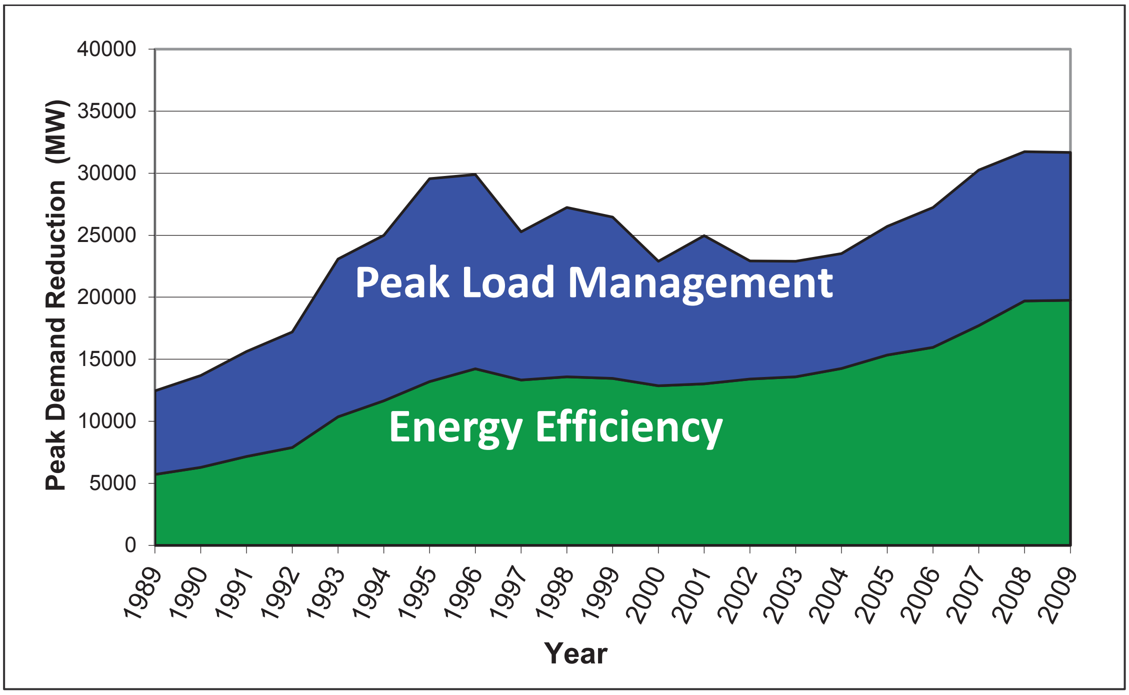


Figure 3-2 US peak demand reduction from Load Management and Energy Efficiency
(Energy Information Administration, 2011, p.233; International Energy Agency, 2010, p. 72)

There is no obvious technical reason why Australian DM performance in peak demand reduction (1–2% of peak demand) should be so much lower than the US where average reductions of approximately 4.3% of total peak demand have been achieved (see Table 3.2).

[17] Combined energy efficiency and load management energy reductions from International Energy Agency. (2010). CO_2 Emissions from Fuel Combustion – Highlights, p. 72

A comparison of the performances of the US and Australian systems by proportion of National peak demand reduced by DM is shown below in Table 3-3.

Table 3-3 Comparison of US and Australian demand management performance

Year	Australian / US savings ratio
2008/09	18.8%
2009/10	22.8%
2010/11	47.0%*

*Based on forecast in the SENDMA.

3.2 Survey of electricity network DM in Australia

3.2.1 Survey method

I developed the initial scope of the SENDMA in collaboration with project partners and A2SE to include the following survey elements:

- data for the previous two years and the current financial year on expenditure for DM (i.e. DM initiatives in place during 2008/09 and 2009/10 and plans for 2010/11)
- the resulting value of savings for customers and avoided network expenditure
- the resulting energy and demand outcomes in MWh and kW
- responses from the major electricity distribution and transmission network service providers (NSPs), but not electricity retailers.

For the purposes of this study, DM was defined, consistent with the definition in Chapter 1, as 'any action undertaken by the supplier of the good or service to influence the timing or overall demand by consumers, as an alternative to supplying that good or service'. In the context of this research, DM includes peak load management, end use energy efficiency, distributed generation and time-of-use meters and tariffs, as defined in Table 3-4 below.

Table 3-4 Definition of demand management types

Load management (LM)	Includes, but is not limited to, direct load control, demand response, interruptible loads, load shifting, power factor correction (in customer premises, but not within the network), fuel substitution and integrated DM projects (including elements of LM, EE, DG and ToU)
Energy efficiency (EE)	Primarily refers to end-use efficiency, e.g. delivering equal or greater levels of 'energy services' with less energy supply: cooling, heating, lighting, driving motors, operating equipment and appliances, etc.
Distributed generation (DG)	Refers to energy generators embedded within the network, typically less than 30MW capacity, and includes, but is not limited to, solar photovoltaics, wind, small-scale hydroelectric, biomass/biogas, cogeneration, trigeneration, diesel, fuel cells and standby generation.
Time of use (ToU) meters and tariffs	ToU meters are meters that include functions to measure energy at its time of use, where data are either manually or electronically retrieved. Time-of-use tariffs are tariffs that use this time-of-use data for billing purposes, usually with the aim of influencing behaviour in regards to energy use.

In order to ensure that the survey reflected current data conventions of Australian distribution network service providers (NSPs), it was necessary to consider the DM regulations that were applied by the relevant economic regulator and portfolio agencies in each jurisdiction across Australia. This included a review of policy and regulatory instruments such as the New South Wales and Western Australian D-Factors, the DM Innovation Allowance in Victoria, South Australia, Queensland and New South Wales, the Queensland Government's Energy Conservation and Demand Management Program and energy efficiency schemes such as the New South Wales Energy Savings Scheme, the South Australian Residential Energy Efficiency Scheme and the Victorian Energy Efficiency Target.

International precedents were also reviewed for DM surveys of electricity service providers, including the US Department of Energy's Annual Electric Power Industry Survey and Report (US DOE 2008).

A draft survey instrument was then developed based on the survey elements mentioned above, the review of DM regulations in Australia and a review of international DM survey precedents. The draft SENDMA was distributed to the project steering committee, project partners and three NSPs with a request for feedback on the survey format and content. Feedback was received from all parties and was addressed in the final version of the survey.

After the SENDMA survey instrument was finalised[18], each electricity network service provider was contacted to confirm the most appropriate contact to receive the survey. Project team members sought to have an initial phone conversation with each appropriate contact before distributing the cover letter and survey to the NSPs.

The following electricity NSPs received the SENDMA survey.

Table 3-5 NSPs that received and responded to the SENDMA survey

Company	**State**	**Response received**
ActewAGL	ACT	Yes
Country Energy	NSW	Yes
Energy Australia	NSW	Yes
Integral Energy	NSW	Yes
TransGrid	NSW	Yes
Power and Water Corporation	NT	Yes
Energex	QLD	Yes
Ergon Energy	QLD	Yes
Powerlink Queensland	QLD	Yes
Electranet Pty Ltd	SA	Yes
ETSA Utilities	SA	Yes (09/10 only)
Aurora Energy	TAS	*No*
Transend Networks	TAS	Yes
Citipower	VIC	Yes
Jemena	VIC	Yes
Powercor Australia	VIC	Yes
AusNet Services	VIC	Yes
United Energy Distribution	VIC	Yes
Horizon Power	WA	Yes
Western Power	WA	Yes

(Source: Dunstan et al., 2011d)

[18]The survey was conducted in accordance with the ISF Code of Ethics. The Code of Ethics was followed throughout this research project, including rules governing informed consent, privacy and anonymity, and confidentiality for respondents unless consent has been given. For example, the DM data from network service providers is included in this report but no individuals are identified.

The SENDMA survey was circulated mid-November 2010 and the majority of responses were received by the end of 2010. My colleagues and I were available during this response period to answer questions or support NSPs with data entry.

Data analysis from the SENDMA survey is presented below. It is important to remember that NSPs are at different stages in their DM rollouts, and so not all organisations were able to complete every section of the survey at this time. However, as a key aim of the survey was to set a baseline with a view to gathering data regularly, if not annually (as is done in the US), it was recognised that the current set would be incomplete.

Of the 19 respondents, 16 had DM data to report, and of these, three had data in all four sections of the survey: Load Management, Energy Efficiency, Distributed Generation and Time of Use (see SENDMA report for complete summary of data submitted).

Based on the data received from the SENDMA survey, the following results are presented below:

- participation by state and territory
- overview of the data collected
- energy savings by type, sector and state
- demand reductions by type, sector and state
- emissions reductions by DM type, sector and state
- expenditure on DM projects
- cost-effectiveness by type and sector.

3.2.2 Participation by state and territory

The network businesses in seven of the eight states and territories reported projects within their service areas. Table 3-6 summarises the number of responding network businesses and the number of reported projects by state.

Table 3-6 Number of respondents and projects by state

State	Respondents per state	Total potential respondents	DM Projects (LM, EE, DG)*
Australian Capital Territory	1	1	1
New South Wales	4	4	53
Northern Territory	1	1	2
Queensland	3	3	17
South Australia	2	2	27
Tasmania	1	2	0
Victoria	5	5	6
Western Australia	2	2	9
Total	**19**	**20**	**115**

(Source: Dunstan et al., 2011d)

*Time-of-use tariffs were excluded from this summary as no data was reported on the energy or demand impacts of these measures (except, however, where specifically mentioned in an LM project).

The network businesses in New South Wales reported 53 projects (46% of total nationally reported projects), followed by those in South Australia (27, 23%), Queensland (17, 15%) and Western Australia (9, 8%).

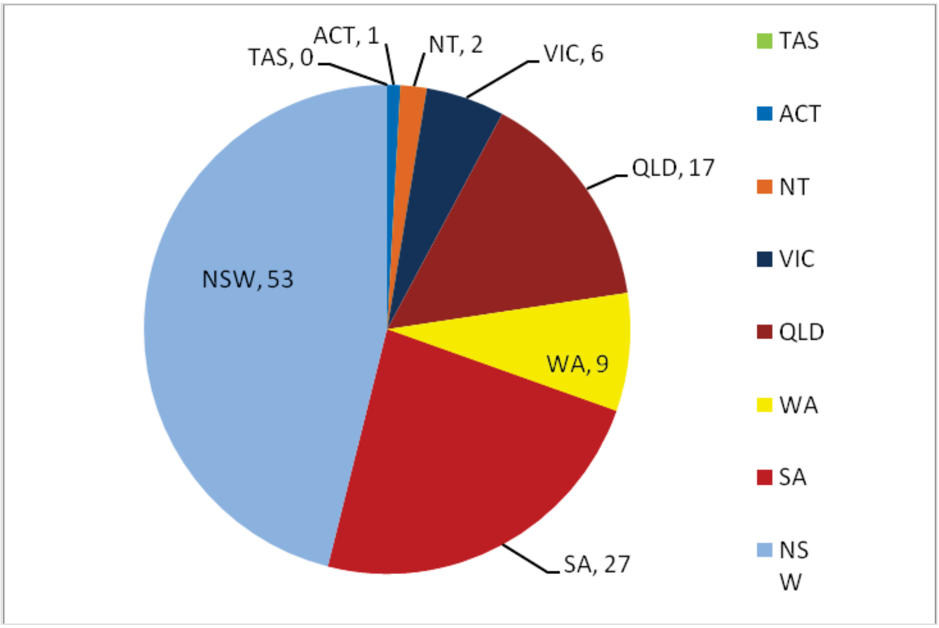


Figure 3-3 Number of LM, EE, DG projects by state

(Dunstan et al., 2011d)

The network businesses in Tasmania did not report any projects.

3.2.3 Overview of survey data

About the responding organisations

The current 20 transmission and distribution network service providers (NSPs) in Australia's states and territories were contacted to contribute to this survey. Written responses were submitted by 19 NSPs.

The NSPs ranged widely in size (i.e. number of employees). The smallest NSP was in the 100–500 employee range, and the largest was in the 5,000–10,000 employee range. The number of full-time equivalent (FTE) staff working on DM within each NSP varied from six NSPs reporting no staff dedicated to DM to two NSPs reporting DM teams of over 40 FTE staff.

Table 3-7 Number of full time equivalent (FTE) staff working on DM

Size range of FTE staff dedicated to DM	Number of NSPs
0 FTE	6
1 - 5 FTE	8
11 - 20 FTE	3
> 20 FTE	2 (reported over 40 FTE)

(Source: Dunstan et al., 2011d)

3.3 Survey results

3.3.1 Energy savings

Energy savings were included for 35 of the 115 projects. Savings were reported in MWh and they are aggregated in GWh in Table 3-8 below.

The reported energy savings are presented in the sections below by: the type of DM technology that produced the savings, the state or territory in which the savings occurred; and, the sector in which the savings were achieved.

Energy savings by type of DM

The total energy savings for the three reporting years was 410 GWh, with an average savings of 136.7 GWh per year. This average energy saving represents 0.2% of Australia's 2008/09 electricity consumption of 204,301 GWh (ESAA, 2010). Note that 'energy savings' includes energy production from DG projects, as well as energy savings from LM and EE projects.

Table 3-8 Reported energy savings (GWh) resulting from LM, EE, DG and ToU

	08/09 (GWh)		09/10 (GWh)		10/11 (GWh)		No. of projects
Load management	1.1	0.3%	1.2	4%	16.3	32%	28
Energy efficiency	27.1	8%	28.9	96%	34.0	66%	5
Distributed generation	300.0	91%	0.004	0%	1.1	2%	6
Total	**328.2**		**30.1**		**51.3**		**39**

(Source: Dunstan et al., 2011d)

The graph below compares the reported energy savings in GWh derived from DG, EE and LM.

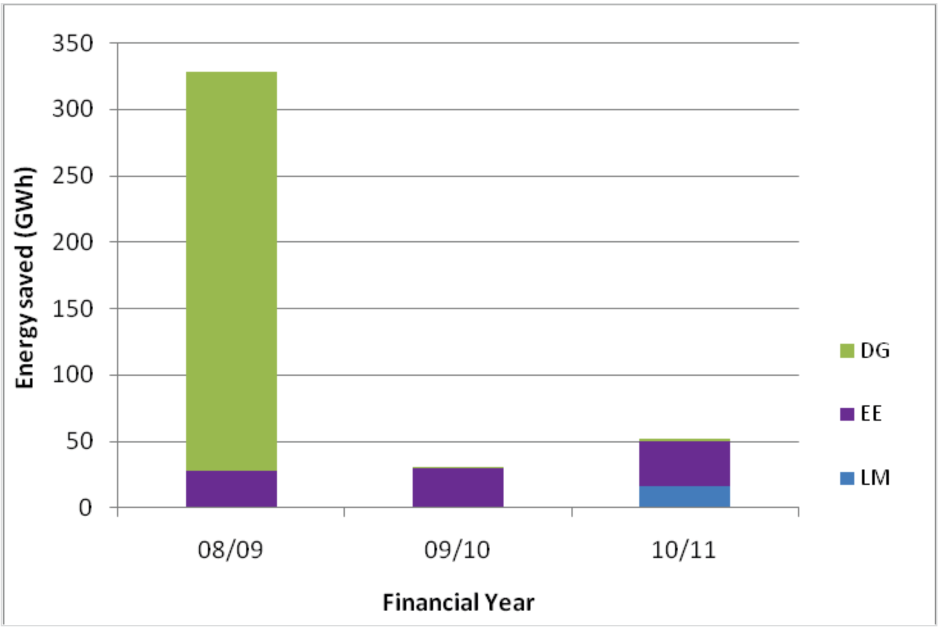


Figure 3-4 Reported energy saved (GWh) by DG, EE and LM projects
(Dunstan et al., 2011d)

Data was submitted for one large industrial DG project in 2008/09 only (representing two generators), showing energy production of 300 GWh which accounts for 91% of the energy saved in that year (Note that generation data was only supplied for the first reporting year of the survey).

Apart from this project, the majority of reported energy savings (GWh) came from five EE projects delivering an average of 30 GWh over the three reporting years.

In 2008/09, 15 LM projects produced 1.1 GWh of energy savings, and in 2009/10, 13 LM projects produced 1.2GWh; this figure rose to 16.3 GWh in 2010/11. The energy savings from the remaining five DG projects accounted for less than 2% of total energy savings over the three reporting years.

Energy savings by state

The NSPs in four of the eight states and territories reported energy savings: New South Wales, Queensland, Western Australia and South Australia.

Table 3-9 Reported energy savings (GWh) by state and territory*

State	08/09 (GWh)		09/10 (GWh)		10/11 (GWh)		No. of projects
NSW	327.8	99.9%	27.8	92%	27.5	54%	29
QLD	0.5	0.1%	2.3	7%	22.7	44%	6
WA	0	0%	0.004	0%	1.1	2%	3
SA	0	0%	0.003	0%	0	0%	1
Total	**328.2**		**30.1**		**51.3**		**39**

(Source; Dunstan et al., 2011d)

*The Australian Capital Territory, the Northern Territory, Tasmania and Victoria did not have any reported energy savings.

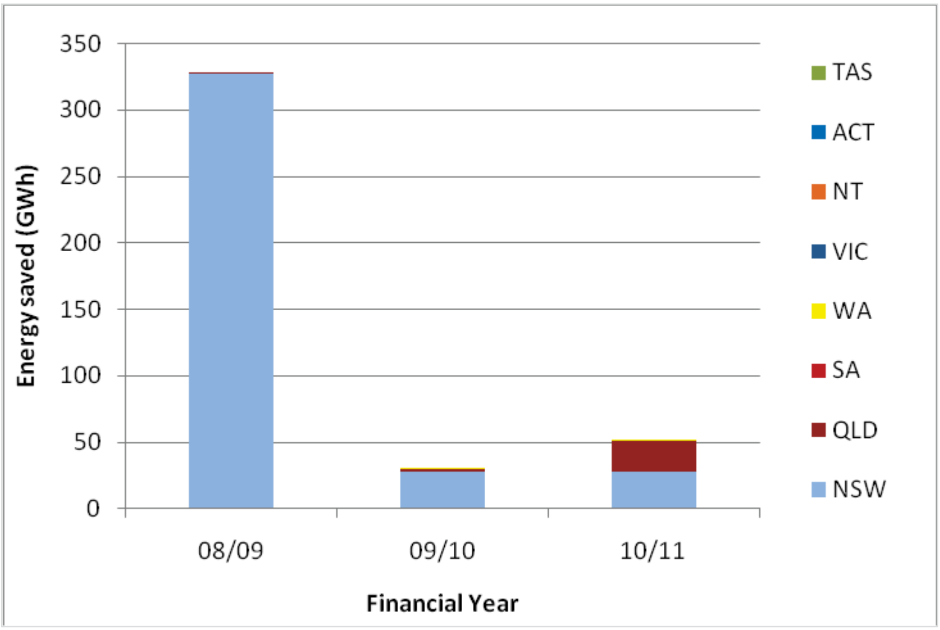


Figure 3-5 Reported energy savings (GWh) by state and territory (Dunstan et al., 2011d)

The majority of reported energy savings occurred in New South Wales (99.9% in 2008/09; 92% in 2009/10; 54% in 2010/11). Queensland NSPs reported increasing energy savings across the three reporting years from 0.5 GWh in 2008/09 to 23 GWh in 2010/11. Western Australia's energy savings rose from zero in 2008/09 to 4 MWh in 2009/10 to 1.1 GWh in 2010/11.[19] South Australian NSPs reported energy savings of 3 MWh in 2009/10 (but did not report for 2008/09 or 2010/11).

[19] Attributable primarily to a DG project in regional WA.

Energy savings by sector

The energy savings were attributed to the sector in which the savings occurred: residential, commercial, industrial or mixed ('mixed' refers to DM projects in which industrial and commercial sectors were both engaged and the energy savings were not separated).

Table 3-10 Reported energy savings (GWh) by sector

	08/09 (GWh)		09/10 (GWh)		10/11 (GWh)		No. of projects
Residential	27.5	8%	29.3	97.7%	34.4	67%	6
Commercial	0.048	0%	0.007	0%	16.5	32%	11
Industrial	300.1	91%	0.039	0.1%	0.05	0.1%	12
Mixed	0.5	0.2%	0.66	2.2%	0.35	0.7%	10
Total	**328.2**		**30.1**		**51.3**		**39**

(Source: Dunstan et al., 2011d)

Industrial energy savings ranged from 300 GWh (2008/09) (due to one large DG project with data only for that year) to 39 MWh (2009/10) and 50 MWh (2010/11).

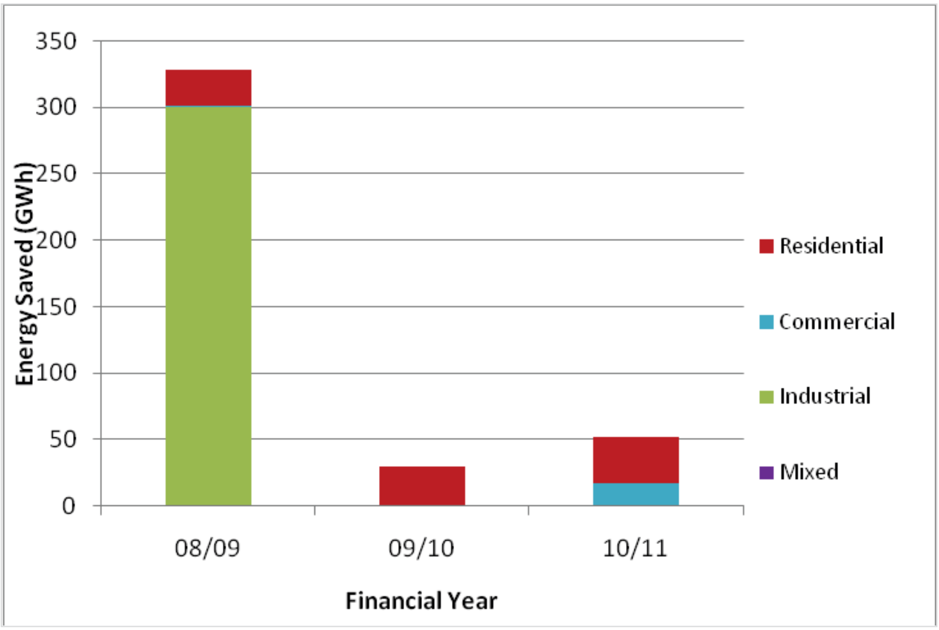


Figure 3-6 Reported energy savings (GWh) by sector

(Dunstan et al., 2011d)

In the three reporting years, the residential sector provided consistent energy savings (28 GWh in 2008/09 via two reported projects; and 29 GWh in 2009/10 and 34 GWh in 2010/11 via four reported projects). The commercial sector provided 48 MWh (0.2% of total energy savings from network DM) in 2008/09, and 7 MWh in 2009/10 (0.02%), before rising to 16.5 GWh (32%) in 2010/11, via seven projects. The energy savings from 'mixed' sector projects averaged 510 MWh for the three reporting years (520 MWh in 2008/09; 660 MWh in 2009/10; 350 MWh in 2010/11).

3.3.2 Cost effectiveness of energy savings

Cost effectiveness (expenditure in $/MWh per year) was calculated for DM types, the state or territory in which the project occurred and the sector in which the project occurred.

Seven of the 115 DM projects reported both expenditure (capex and opex) and energy savings and only these seven projects are analysed in this section and the results are summarised in Table 3-11 below. Data was summed for the three reporting years where available.

Table 3-11 Cost effectiveness (expenditure/MWh) of DM projects for 2010/11

Project Name	DM Type	State	Technology	Cost ($m)	Energy Savings (MWh/year)	Cost Effectiveness ($/MWh/yr)
Network Demand Management	LM	QLD	Mixed	2.31	15,402	150
Powersavvy	EE	QLD	EE	7.00	7,250	966
Energy Savers Pilot	EE	QLD	EE	1.78	1,400	1,272
Nelson Bay Relocatable 11kV Generators*	LM	NSW	SG	0.01	700	7
Ravensthorpe Community Energy Project	EE	WA	EE	0.035	56	625
DG - Commercial	DG	WA	DG	0.24	8	30,000
Standby Generation	LM	SA	SG	0.53	3	175,000

(Source: Dunstan et al., 2011d)

* The majority of expenditure occurred in years prior to reporting period.

The total reported cost of these seven projects over the three-year data collection period was $11.9m and the total savings over these three years was 25 GWh.

Four of the projects had a cost-effectiveness value of less than $1,000/MWh, accounting for 79% of the value of the projects (two LM and two EE projects). One EE project had a cost-effectiveness of between $1,000/MWh and $10,000/MWh, while the other two projects had a cost-effectiveness of greater than $10,000/MWh.

The LM project in South Australia, with cost-effectiveness measured at $175,000/MWh, also reported a 760kW reduction in peak demand with a cost-effectiveness of $691/kW, indicating that this project was carried out for peak load reduction rather than energy savings purposes.

The DG project in WA, with a cost-effectiveness measured at $30,000, also reported a cost-effectiveness of $8,000/kW. This project is a utility-owned solar PV power system, and these costs were consistent with the cost of this technology at the time.

By way of comparison, the AEMC currently sets it market price cap (MPC) at $13,500/MWh (AEMC Reliability Panel, 2014).

The logarithmic graph below illustrates the cost-benefit ratio of DM energy savings projects by comparing the cost-effectiveness of these projects to the overall expenditure for each project. The state in which the project was implemented is also noted by colour.

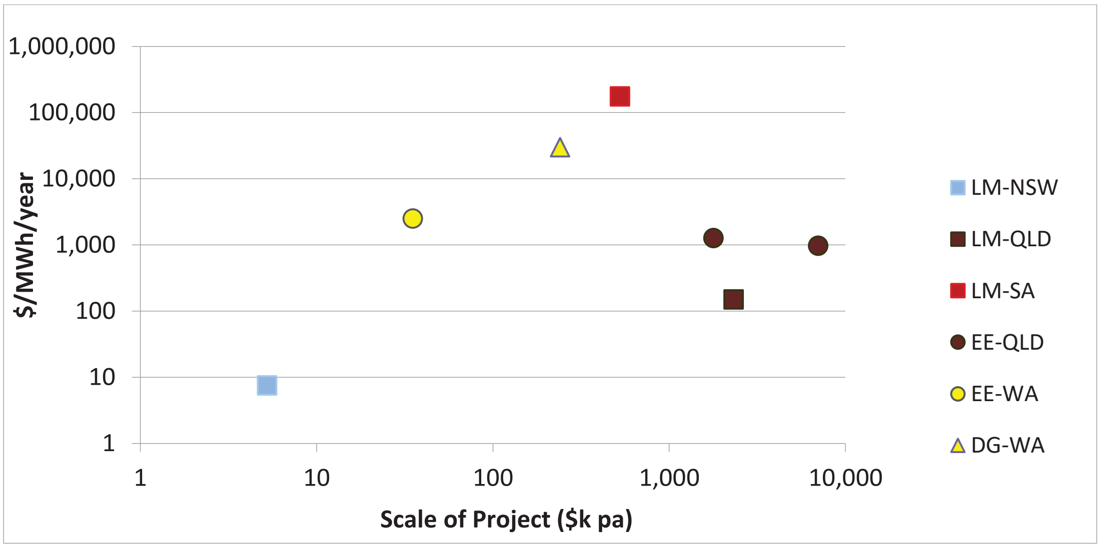


Figure 3-7 Cost effectiveness of DM energy savings compared to total project cost[20] (Dunstan et al., 2011d)

As mentioned above, the LM project in South Australia (LM-SA) was probably carried out for peak load reduction rather than energy savings purposes. The DG project in Western Australia (DG-WA) had a cost-effectiveness of $30,000/MWh, and also reported 30kW in peak demand reduction, having a cost-effectiveness of $8000/kW.

[20] Cost effectiveness (CE) was calculated using the following factors, including cost ($), energy (MWh), and the reporting years (2008/09, 09/10, 10/11) and equation:
$CE = (\$_{08/09} + \$_{09/10} + \$_{10/11}) / (MWh_{08/09} + MWh_{09/10} + MWh_{10/11})$

3.3.3 Peak demand reduction

Most of the projects reported were implemented for peak demand reduction purposes (97 of 115 projects), and were measured in kW or kVA peak reduced, aggregated here in MW. Of the 97 projects reported as load management projects, 60 reported peak demand reductions.

The reporting of demand reduction was season specific. For example, demand reductions were reported as: reductions in summer load only (40 projects), reductions in winter load only (four projects), reductions in both summer and winter load (18 projects) and available reserve demand (two projects). The differing methods of reporting seasonal demand reductions have implications for aggregating the data. In regards to the 18 projects that provided summer and winter peak reductions, adding the winter to the summer peak reductions would have involved doubling up of data and therefore the impacts of the projects. Of the 115 DM projects, 22 reported winter peak load reductions accounting for 16% of the total demand reduction (based on 2010/11 data). To avoid double counting, only the summer reductions and annual reductions have been included in the analysis, as this represents the majority of the data. However projects with winter data have been included in the project-by-project analysis in Section 5.4 where relevant data is available.

The average total demand reduction for the three reporting years was 193 MW. The reported demand reduction is presented in the sections below by: the type of DM technology, the state or territory in which the project was implemented, and the sector in which the reduction was achieved.

Peak demand (MW) reduction by type

As shown in Table 3-12 below, all of the demand reduction is reported from LM, EE and DG projects (with none reported under ToU meters and tariffs).

Table 3-12 Reported demand reduction (MW) by LM, EE and DG

	08/09 (MW)		09/10 (MW)		10/11 (MW)		No. of projects
Load Management	50.9	59%	85.1	67%	310.1	84%	60
Energy Efficiency	0.0	0%	0.0	0%	1.1	0%	4
Distributed Generation	35.3	40.9%	41.1	33%	56.4	15%	6
Total	**86.2**		**126.2**		**367.5**		**70**

(Dunstan et al., 2011d)

Figure 3-8 below summarises the peak demand reduction (MW) for the past three reporting years as a result of the reported DG and LM projects.

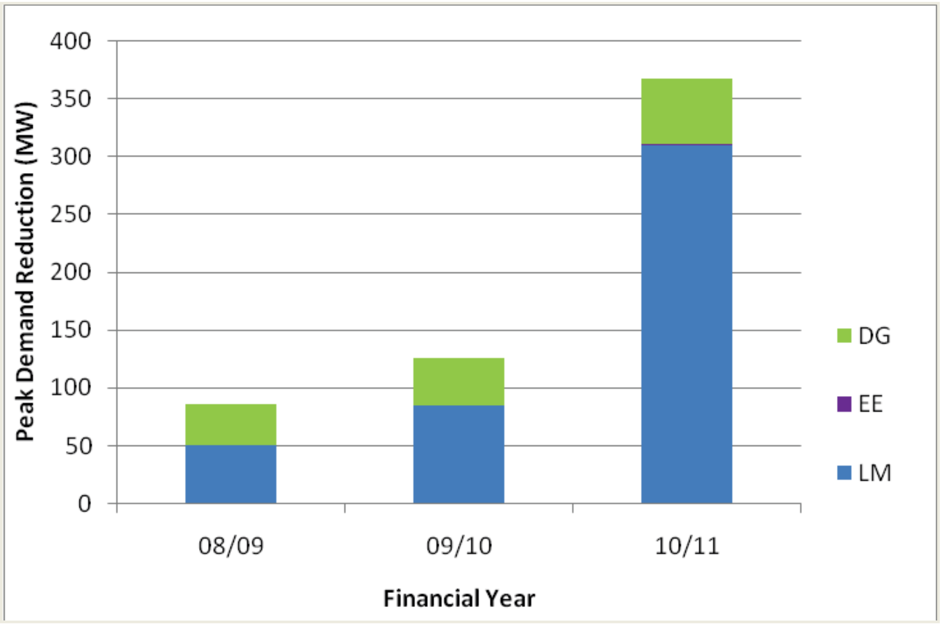


Figure 3-8 Peak demand (MW) reduction by DG and LM
(Dunstan et al., 2011d)

For the three years covered by the survey, the majority of peak demand reduction was achieved through load management (LM) projects (51 MW (59%) in 2008/09; 85 MW (67%) in 2009/10; and 310 MW [85%] in 2010/11). Over the three reporting years, DG contributed an average of 44 MW of demand reduction, contributing an increasing amount over time (35 MW (41% of total DM for all DM types) in 2008/09, 41 MW (33%) in 2009/10 and 56 MW (15%) in 2010/11).

In addition to the peak demand reduction data presented in this section, one transmission NSP reported a project implemented for an available reserve of 100 MW (2008/09), and one distribution NSP reported an available reserve of 16.5 MW (2009/10). For the purposes of this survey, 'available reserve demand' was defined as 'reserve capacity available for peak demand management that could have been dispatched' (as opposed to reserve demand that was dispatched, which would have been entered as annual summer and winter peak demand reduction). In other words, available reserve demand reduction is equal to the total capacity of reliable peak load management minus the peak load reduction that was actually dispatched.

Peak demand reduction (MW) by state

Five of the eight states and territories provided data on peak demand reduction. As mentioned above, only the summer reductions and annual reductions have been included in the analysis.

Table 3-13 Reported peak demand reduction (MW) by state and territory

	08/09 (MW)		09/10 (MW)		10/11 (MW)		No. of projects
NSW	16.1	18.7%	33.4	26%	32.6	9%	38
QLD	69.2	80.2%	56.2	45%	332.6	90%	17
SA	0	0%	34	27%	0	0%	8
WA	0	0%	1	1%	1	0%	6
VIC	1	1%	1	1%	1	0%	1
Total	**86.2**		**126.2**		**367.5**		**70**

(Dunstan et al., 2011d)

The Australian Capital Territory, the Northern Territory and Tasmania did not have any reported peak demand reductions. Queensland NSPs reported the majority of peak demand reduction for the three reporting years (69 MW in 2008/09; 56 MW in 2009/10; 332 MW in 2010/11). New South Wales NSPs reported 16 MW in 2008/09 and then relatively consistent peak demand reduction for 2009/10 (33 MW) and 2010/11 (33 MW).

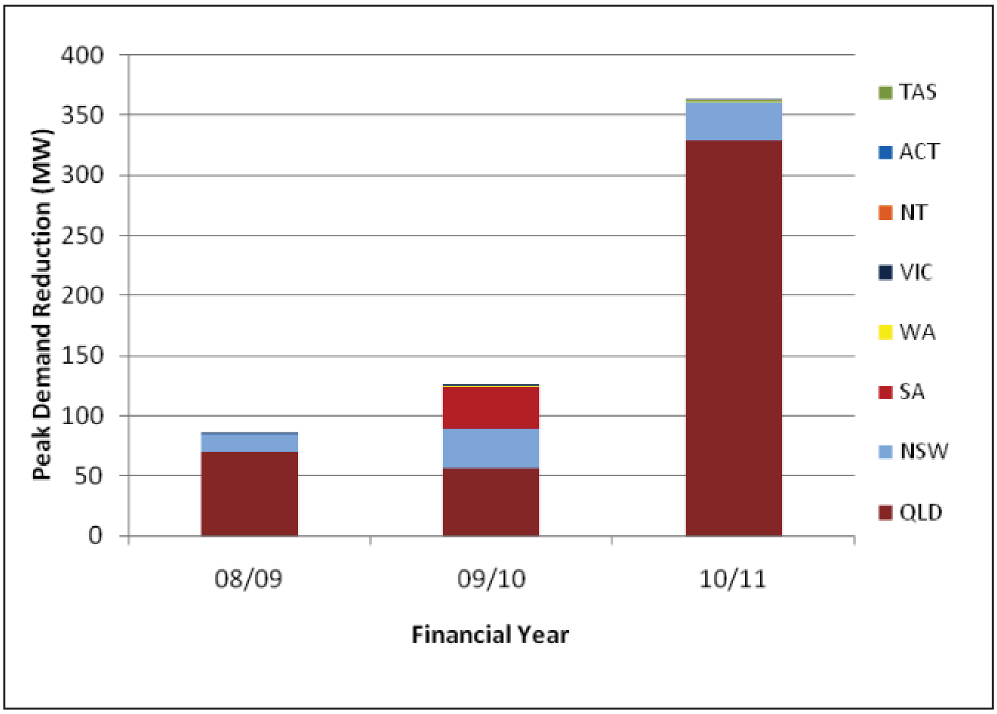


Figure 3-9 Reported peak demand (MW) reduction by state and territory

(Dunstan et al., 2011d)

South Australia contributed a quarter of the peak demand reduction in 2009/10 (34 MW, 27%). Victorian NSPs reported increasing demand reduction over the three-year period from 1 MW in 2008/09 to 1.3 MW in 2009/10 and 1.4 MW in 2010/11. Western Australian NSPs reported 0.9 MW demand reduction in both 2009/10 and 2010/11.

In 2008/09 an available reserve demand reduction project accounted for two-thirds of New South Wales's reported peak demand reduction for that reporting year. This project did not report any dispatched peak reduction, and therefore it is not included above.

Peak demand reduction by sector

Total peak demand increased over the three-year reporting period from 86.2 MW to 367 MW.

Table 3-14 Reported peak demand reduction (MW) by sector

	08/09 (MW)		09/10 (MW)		10/11 (MW)		No. of projects
Residential	2.8	3%	8.5	6.7%	296.1	81%	18
Commercial	75.0	87.0%	57.9	46%	59.4	16%	17
Industrial	1.0	1%	2.0	1.6%	1.4	0.4%	15
Mixed	7.5	8.7%	57.8	45.8%	10.7	2.9%	20
Total	**86.2**		**126.2**		**367.5**		**70**

(Dunstan et al., 2011d)

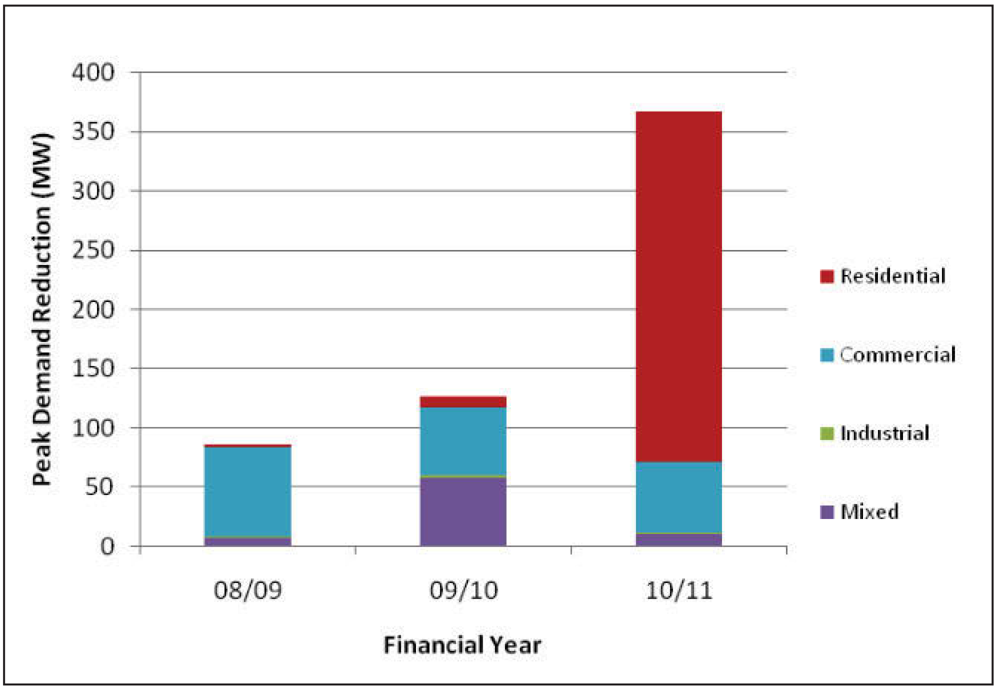


Figure 3-10 Peak demand (MW) reduction by sector
(Dunstan et al., 2011d)

Residential projects accounted for 296 MW (81%) of peak reductions in 2010/11, up from 8.5 MW in 2009/10, and 2.8 MW in 2008/09. Commercial projects accounted for around 75 MW of peak demand reduction in 2008/09, dropping to 57.9 MW in 2009/10 and 59.4 MW in 2010/11. Industrial projects made up 950 kW of peak reductions in 2008/09. This figure increased to 2 MW in 2009/10 and dropped to 1.4 MW in 2010/11. Mixed projects made up 7.5 MW of peak reductions in 2008/09, increased to 57.8 MW in 2009/10 and dropped to 10.7 MW in 2010/11.

3.3.4 Cost effectiveness of peak demand reduction

The cost-effectiveness of peak demand reduction was more widely reported than the cost-effectiveness of energy savings (expenditure/MWh), and cost benefit ratios (cost-effectiveness/total project expenditure).

The cost-effectiveness of peak demand reduction (expenditure/kW) was calculated for DM types and by project. Cost effectiveness represents the sum of expenditures ($) versus the total of all peak reductions (kW). A total of 33 projects, summarised in Table 3-15 below, had both peak reduction and expenditure data, and therefore only these projects are included in the cost-effectiveness analysis. Data for all years was used for cost-effectiveness calculations, giving cost-effectiveness in $/kW/year.

Table 3-15 Peak demand reduction cost-effectiveness of DM projects ($/kW/year)

Project Name	DM Type	State	Technology	Cost ($m)	Peak reduction (kW)	Cost Effectiveness ($/kW/year)
Western 500kV Conversion	LM	NSW	Other	7.58	100,000	76
Load control upgrades	LM	NSW	DLC	2.64	7,100	371
Warringah STS DM Project	LM	NSW	Mixed	1.60	7,400	216
Greenacre – DM Project 2009/10	LM	NSW	Mixed	0.79	3,700	214
Nelson Bay Relocatable 11kV Generators*	LM	NSW	SG	0.01	14,000	0.4
Terrey Hills PFC and Generator Project	LM	NSW	Mixed	0.73	3,080	237
Willoughby STS DM Project	LM	NSW	Mixed	0.59	4,700	126
Adamstown DM Project*	LM	NSW	SG	0.03	2,500	11
Eastern St George PFC Project	LM	NSW	PFC	0.01	840	15
Kurri 33kV Feeder & Kurri Zone PFC Project	LM	NSW	PFC	0.02	450	46
Summer Preparedness	LM	QLD	Other	6.81	71,000	96
Cool Change 2	LM	QLD	DLC	3.39	225	15,083
Energy Conservation Communities	LM	QLD	EE	9.12	3,000	3041
Residential Targeted Initiative	LM	QLD	Other	6.38	5,000	1275
DM for Commercial & Industrial	LM	QLD	Mixed	7.74	10,000	774
Network Demand Management	LM	QLD	Mixed	2.31	2,500	926
Solar City	LM	QLD	EE	0.44	1,008	437
Air Con Trial	LM	QLD	DLC	0.25	16,651	15
Power Factor Correction	LM	SA	PFC	0.68	33,064	21
Standby Generation	LM	SA	SG	0.53	760	691
Direct Load Control	LM	SA	DLC	14.20	275	51,619
Voluntary & Curtailable Load Control for Large Customers	LM	SA	LS	0.30	303	1,000
Peak Load management	LM	VIC	TAR	0.28	3,615	78
Community Energy Project	LM	WA	EE	0.26	510	518
Fuel switching	LM	WA	FS	0.03	108	254
AC Direct Load Control Trial	LM	WA	DLC	0.64	300	2,125
Neutral Bay Residential DM Project*	EE	NSW	EE	0.001	335	1.7
Powersavvy	EE	QLD	EE	7.00	904	7,743
Energy Savers Pilot	EE	QLD	EE	1.78	494	3,606
DG – Commercial	DG	NSW	DG	0.95	7,800	122
DG – Commercial	DG	QLD	DG	0.67	3,000	223
DG – Residential	DG	WA	DG	3.00	1,695	1,770
DG – Commercial	DG	WA	DG	0.24	30	8,000

(Dunstan et al., 2011d)

* The majority of expenditure occurred in years prior to reporting period.

Ten of the projects in Table 3-15 had a cost-effectiveness of lower than $100/kW/year, thirteen projects had a cost-effectiveness of between $100 and $1000/kW/year, and ten projects had a cost-effectiveness of $1000/kW/year or greater.

The cost-effectiveness values shown in Table 3-15 can be compared to 30 other projects that explicitly reported $/kVA reduction incentives (note these 30 projects were not included in the analysis because they did not provide a full data set). Of these 30 projects, 23 reported customer incentives for load reductions of $70 to $190/kVA and the other seven did not provide incentive data.

The graph below shows the cost-effectiveness of peak demand reduction for the 33 analysed projects compared to their total project costs.

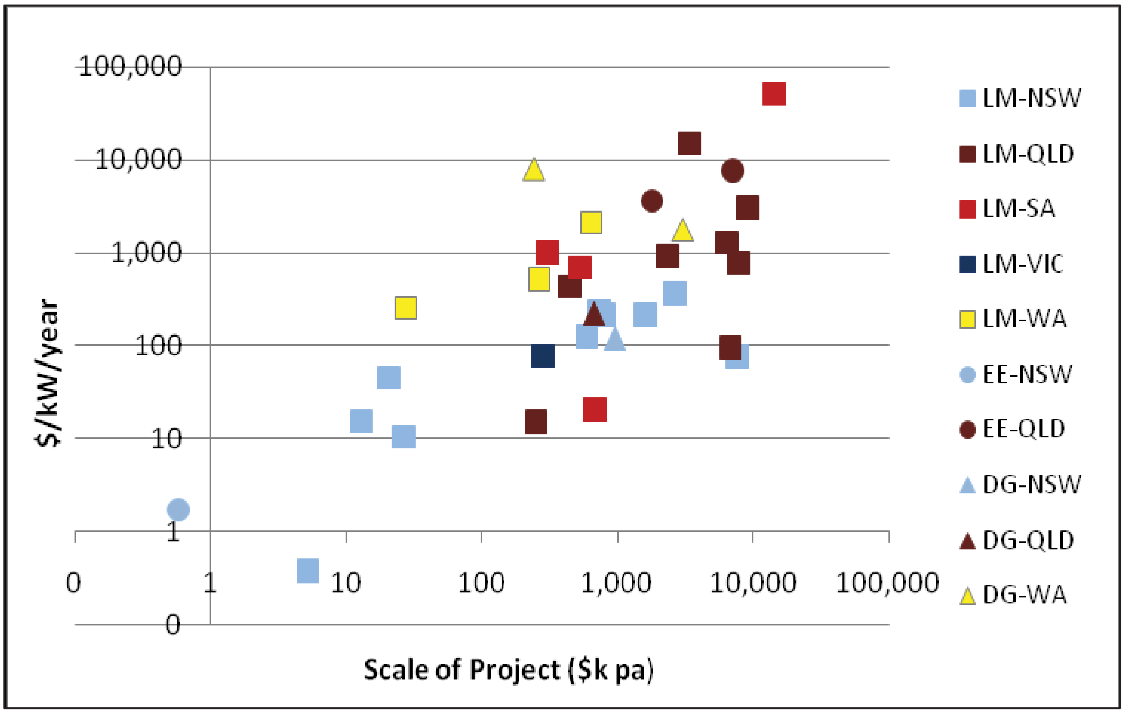


Figure 3-11 Cost effectiveness of peak demand reduction compared to total project cost[21] (Dunstan et al., 2011d)

The average cost-effectiveness was $264/kW/yr.

[21] Cost effectiveness (CE) was calculated using the following factors, including cost ($), demand (kW), and the reporting years (2008/09, 09/10, 10/11) and equation:
$CE = (\$_{08/09} + \$_{09/10} + \$_{10/11}) / (kW_{08/09} + kW_{09/10} + kW_{10/11})$

It is difficult to compare projects on the basis of some of the data provided. Project cost-effectiveness calculations varied for reported reasons such as:

- Three projects are known to have had expenditure in previous years for which data were not collected by the survey, which meant they yielded low results.
- Some projects only had data for one year, where expenditure was given, but not all the savings (or vice versa).
- Some projects were biased by weather conditions, meaning that the kW demand reduction was lower than expected, leading to a higher $/kW/year calculation than anticipated by project proponents.
- Some projects were implemented to reduce the likelihood of losing load, as network capacity was already reached.

3.3.5 Emission reductions

Although emission savings data was not requested from the NSPs, this data was estimated from the energy savings data and greenhouse data published in the National Greenhouse Accounts (NGA) Factors Report (DCCEE, 2010).

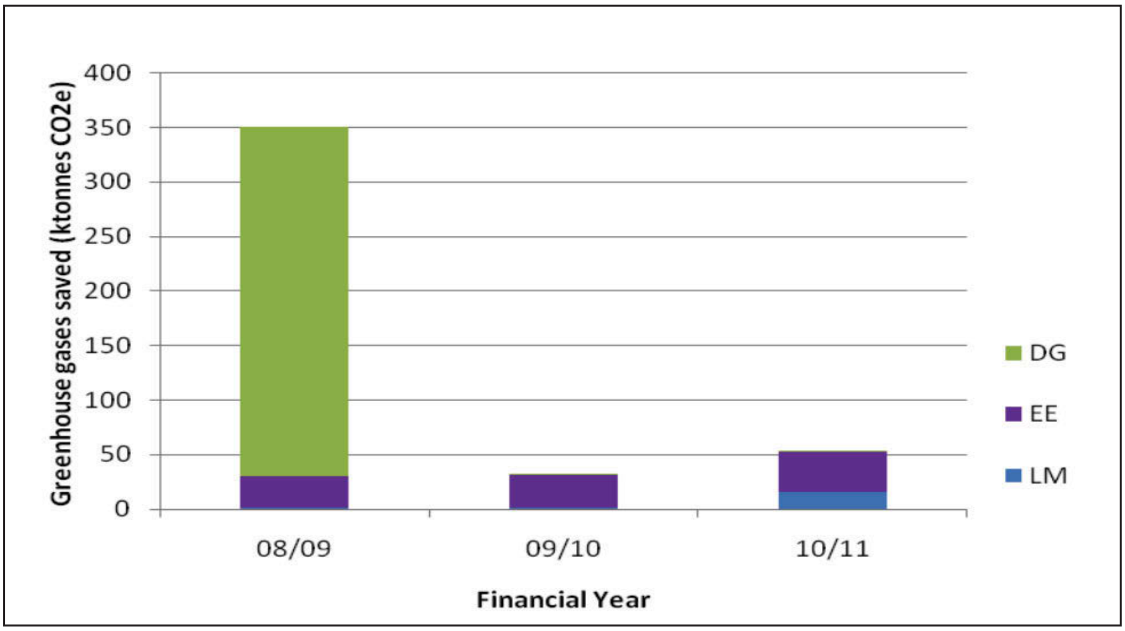


Figure 3-12 Greenhouse gas emission savings by DM type

(Dunstan et al., 2011d)

One distributed generation project (comprising two generators) saved 321 kilotonnes (kt) of greenhouse gas emissions in 2008/09, and three projects were projected to save 1.5 kt in

2010/11. Three EE projects consistently saved approximately 31 kt of greenhouse gas emission each year (8% in 2008/09, 97% in 2009/10 and 68% in 2010/11). Load management projects accounted for 16.0 kt of greenhouse gas emission savings in 2010/11, up from 1.0 kt in 2008/09 and 0.8 kt in 2009/10.

Note that load shifting projects were not included in the greenhouse gas emission savings calculations.

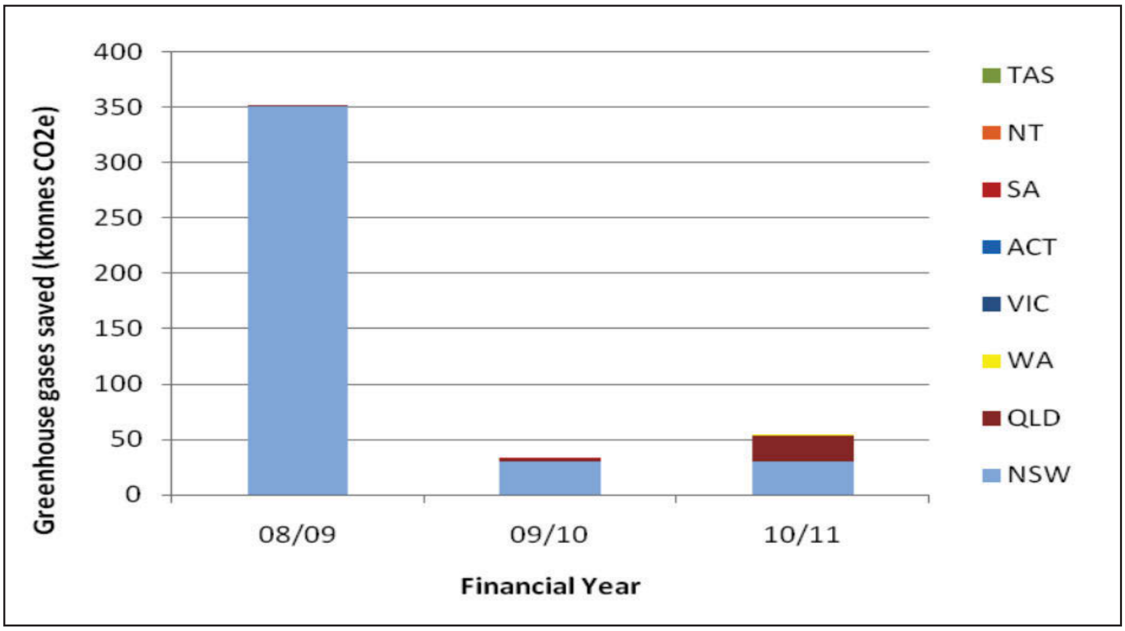


Figure 3-13 Greenhouse gas emission savings by state

(Dunstan et al., 2011d)

Network businesses in three states submitted estimates of greenhouse gas emissions savings (New South Wales, Queensland and Western Australia). Apart from one large project reporting in 2008/09 (321 kt), New South Wales accounted for an average of 30 kt of emissions savings, representing 99% of total emissions savings in 2008/09, 93% in 2009/10 and 55% in 2010/11, based on reported energy savings. Queensland's emissions savings were 460 tonnes in 2008/09 (1.5%), 2.3 kt in 2009/10 (7.2%), and up to 23 kt in 2010/11 (43%). Western Australia's greenhouse gas emissions savings were estimated at 1.0 kt in 2010/11.

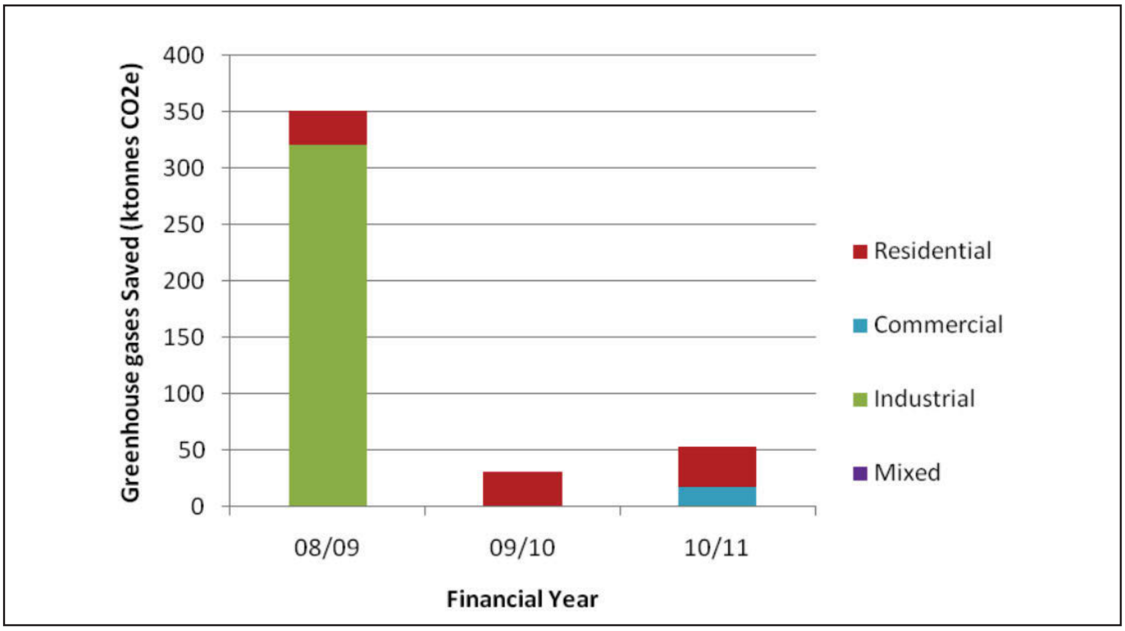


Figure 3-14 Greenhouse gas emission savings by sector

(Dunstan et al., 2011d)

The industrial sector had one large project reporting 321 kt of emissions savings for 2008/09.

The residential sector accounted for an average of 32 kt of greenhouse gas emissions savings per year (29 kt in 2008/09, 31 kt in 2009/10 and 36 kt in 2010/11). The commercial sector accounted for 17 kt in emissions savings in 2010/11, up from less than 60 t in 2008/09 and 2009/10.

3.3.6 Expenditure on DM projects

Expenditure was reported as capital expenditure (capex) costs and operating expenditure (opex) costs. Opex was reported specifically as either incentive costs or employee and other costs. Total DM expenditure on LM, EE and DG increased from \$20m in 2008/09 to \$29m in 2009/10 and \$50m in 2010/11. It was estimated that an additional \$3m and \$162m was to be spent on the New South Wales solar feed in tariff in 2009/10 and 2010/11 respectively. However, this was deemed not to fit the criteria for DM expenditure and was not included in the data or graphs below.

Savings were reported on an annual basis as the value of the capex deferred, and opex savings achieved. A discount rate of 10% (as per the AER Decisions on Cost of Capital) was applied to the reported deferred capex values to give a sense of the savings achieved.

DM expenditure by type

DM expenditure was reported for 44 DM projects. (This does not include the estimated expenditure for the New South Wales solar feed in tariff).

Table 3-16 Reported DM expenditure by project type

	08/09 ($m)		09/10 ($m)		10/11 ($m)		No. of projects
Load management	16.9	87%	21.3	76%	36.7	73%	36
Energy efficiency	0.7	3%	2.8	10%	5.4	11%	6
Distributed generation	2.0	10.0%	3.9	14%	7.9	16%	6
Total	**19.5**		**28.0**		**49.9**		**44**

(Dunstan et al., 2011d)

The expenditure on these 44 LM projects increased over the three reporting years ($16.9m, $21.3m, and $36.7m respectively).

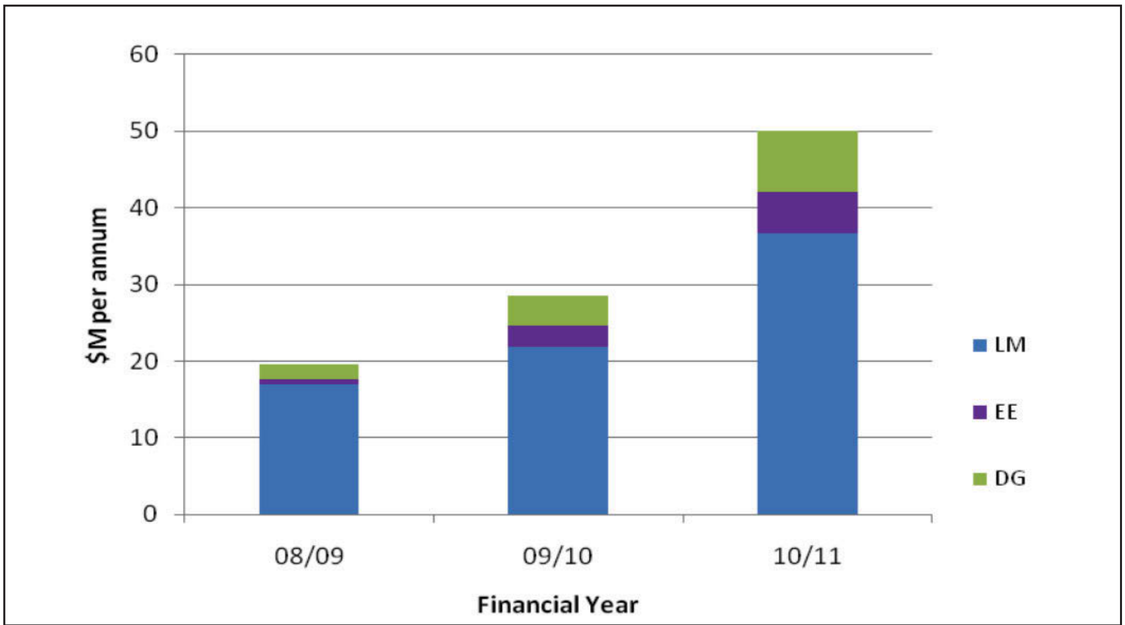


Figure 3-15 DM expenditure by project type

(Dunstan et al., 2011d)

A trend of increasing expenditure was reported for the four DG projects ($2.0m in 2008/09; $3.9m in 2009/10; $7.9m in 2010/11), and for the six EE projects ($0.7m in 2008/09; $2.8m in 2009/10; $5.4m in 2010/11).

DM expenditure by state

The total DM expenditure over the three reporting years was close to $100m. Queensland NSPs reported the largest expenditure ($52m) over the three-year period, followed by New South Wales ($24m) and South Australia ($16m). The Australian Capital Territory and Tasmania did not have any reported DM expenditure.

Table 3-17 DM expenditure by state (excluding the NSW solar Feed in Tariff)

	08/09 ($m)		09/10 ($m)		10/11 ($m)		No. of projects
QLD	6.7	34.1%	13.3	47%	32.1	64%	14
NSW	12.4	63.3%	4.1	15%	7.7	15%	15
SA	0	0%	9	31%	8	16%	6
WA	0	1%	2	6%	2	4%	6
NT	0	1%	0	0%	0	0%	2
VIC	0	0%	0	0%	0	0%	1
Total	19.5		28.0		49.9		44

(Dunstan et al., 2011d)

As shown in the graph below, Queensland and Western Australia increased their expenditure on DM in each successive reporting year.

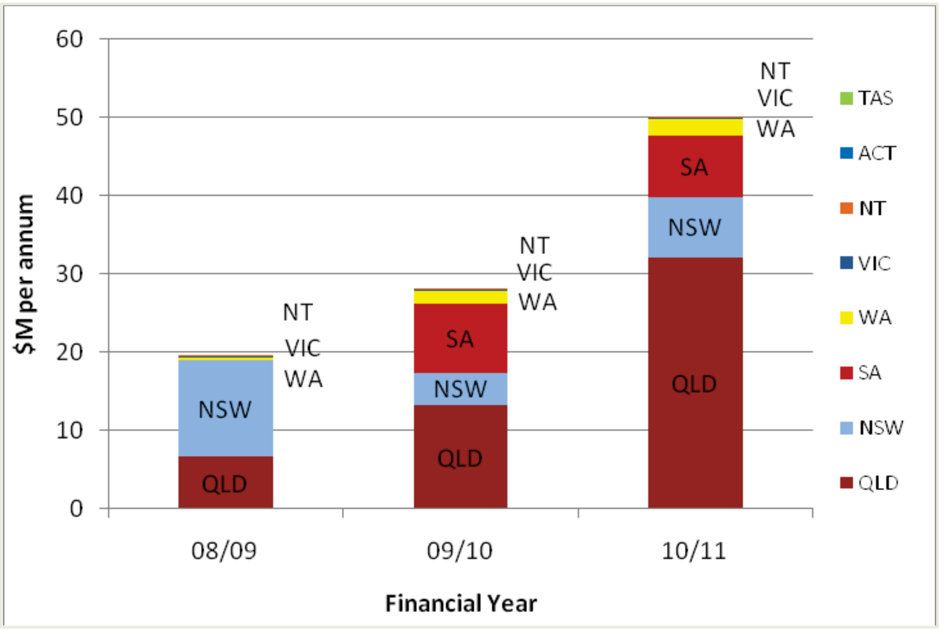


Figure 3-16 DM expenditure by state

(Dunstan et al., 2011d)

DM expenditure by sector

Overall, the greatest amount of expenditure was reported in the residential sector. In 2010/11, expenditure on residential DM projects was reported as $40m, accounting for 80% of DM expenditure, up from $22m in 2009/10, and $5.5m in 2008/09.

Table 3-18 Reported DM Expenditure by sector

	08/09 ($m)		09/10 ($m)		10/11 ($m)		No. of projects
Residential	5.5	28%	21.1	75.6%	40.0	80%	19
Commercial	4.6	23.7%	4.3	15%	7.7	15%	9
Industrial	0.5	3%	1.3	4.7%	0.3	0.6%	3
Mixed	8.9	45.6%	1.2	4.4%	1.9	3.8%	13
Total	19.5		28.0		49.9		44

(Dunstan et al., 2011d)

Expenditure on commercial DM projects in 2010/11 was reported as $7.7m (16% of national expenditure on DM by network businesses), up from $4.3m in 2009/10 and $4.6m in 2008/09. Industrial project expenditure averaged $0.7m over the three years ($0.5m in 2008/09, $1.3m in 2009/10 and $0.3m in 2010/11). Projects in the mixed category accounted for $8.9m in the 2008/09 reporting year (45%), dropping to $1.2m in 2009/10 and $1.9m in 2010/11.

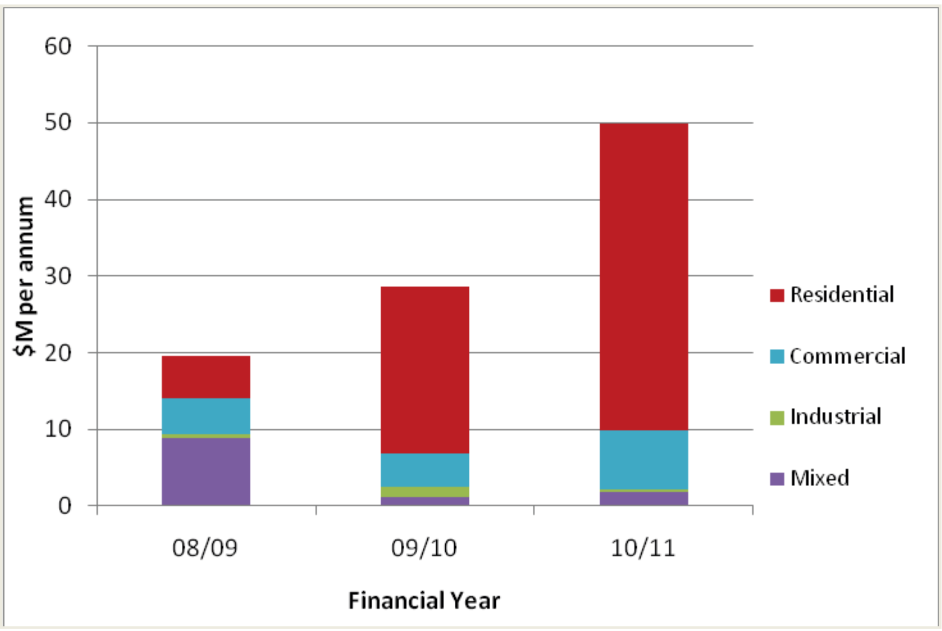


Figure 3-17 DM expenditure by sector

(Dunstan et al., 2011d)

3.4 Cost benefit analysis

The cost/benefit ratio (expenditure/savings) was calculated for 12 projects, submitted by five NSPs that had both expenditure (cost) and savings (benefit) data.

Table 3-19 Cost benefit ratio of DM projects

Project Name	DM Type	State	Technology	Cost ($m)	Benefit ($m)	Cost benefit ratio
Peak demand management	LM	VIC	TAR	0.28	0.60	0.47
Western 500kV conversion	LM	NSW	Other	7.58	40.00	0.19
Load control upgrades	LM	NSW	DLC	2.64	1.05	2.51
Warringah STS DM Project	LM	NSW	Mixed	1.60	2.52	0.63
Greenacre – DM Project 2009/10	LM	NSW	Mixed	0.79	5.90	0.13
Terrey Hills PFC and Generator Project	LM	NSW	Mixed	0.73	0.72	1.01
Willoughby STS DM Project	LM	NSW	Mixed	0.59	0.70	0.84
Eastern St George PFC Project	LM	NSW	PFC	0.01	0.17	0.08
Kurri 33kV Feeder & Kurri Zone PFC Project	LM	NSW	PFC	0.02	0.07	0.29
Powersavvy	EE	QLD	EE	7.00	3.28	2.13
Neutral Bay Residential DM Project*	EE	NSW	EE	0.001	0.004	0.14
DG – commercial	DG	NSW	DG	0.95	2.22	0.43

(Dunstan et al., 2011d)

* Most expenditure occurred in years prior to reporting period.

The total expenditure over the three reporting years for these 12 projects was $22m and the total savings was $57m. The expenditure and savings for these 12 projects for the three reporting years are presented below.

One large reserve capacity project reported expenditure and savings from infrastructure deferral, accounting for 50% of total expenditure and 74% of total savings. Without this significant project, the average yearly expenditure was $2.5m ($3.1m in 2008/09, $2.2m in 2009/10 and $2.3m in 2010/11), and the average yearly savings were $4.7m ($2.3m in 2008/09, $5.8m in 2009/10 and $5.9m in 2010/11).

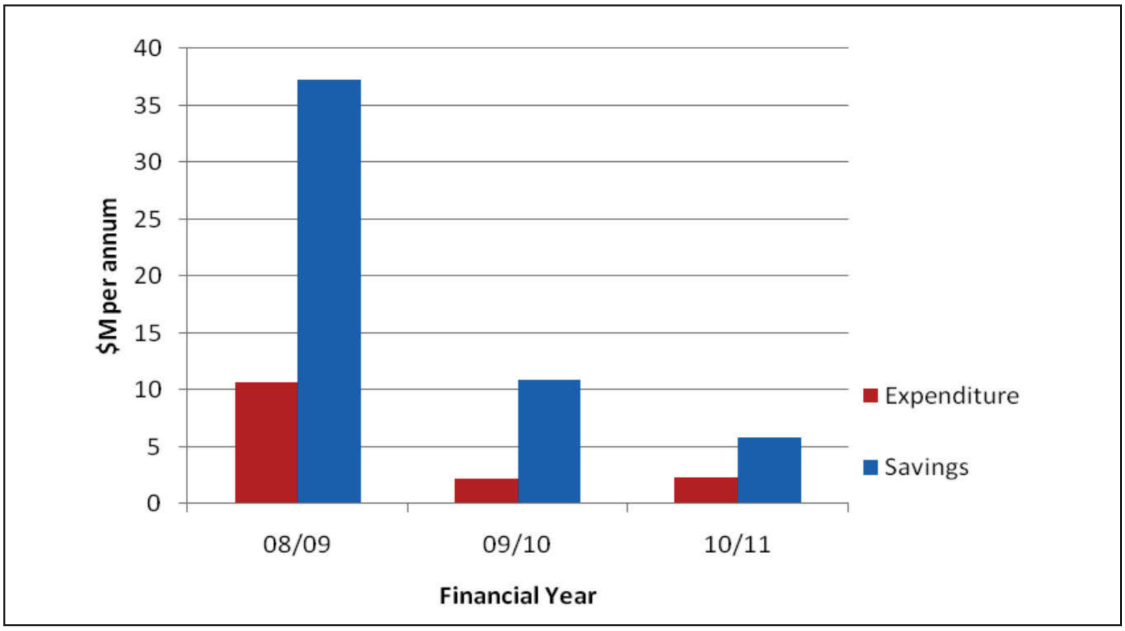


Figure 3-18 Expenditure and savings for all DM projects

(Dunstan et al., 2011d)

Figure 3-19 below shows the cost benefit ratios for the 12 DM projects compared to the total cost of each project.

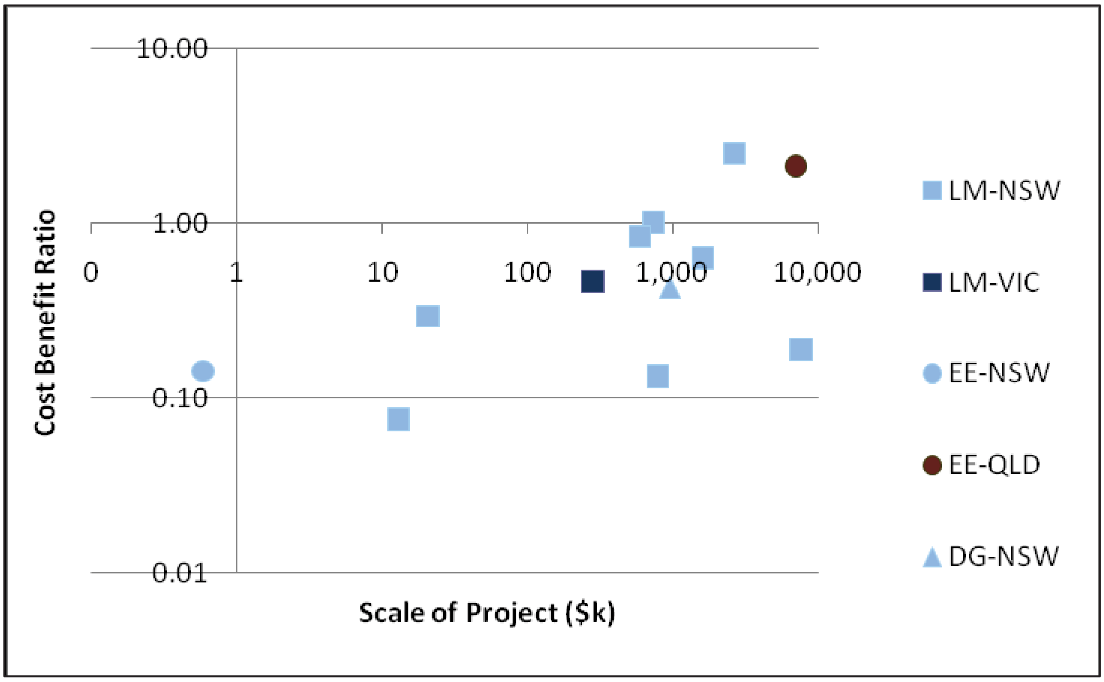


Figure 3-19 Cost benefit ratios for DM projects compared to total cost of project

(Dunstan et al., 2011d)

Nine of the projects had cost/benefit ratios of less than 1, indicating that measured or expected benefits exceeded the reported costs of undertaking the projects. Three of the projects had cost/benefit ratios of greater than 1, ranging from 1.01 to 2.5, indicating that the reported costs were greater than the measured or expected benefits. Figure 3-20 presents the savings versus expenditure ratios, or the cost benefits, of these 12 projects.

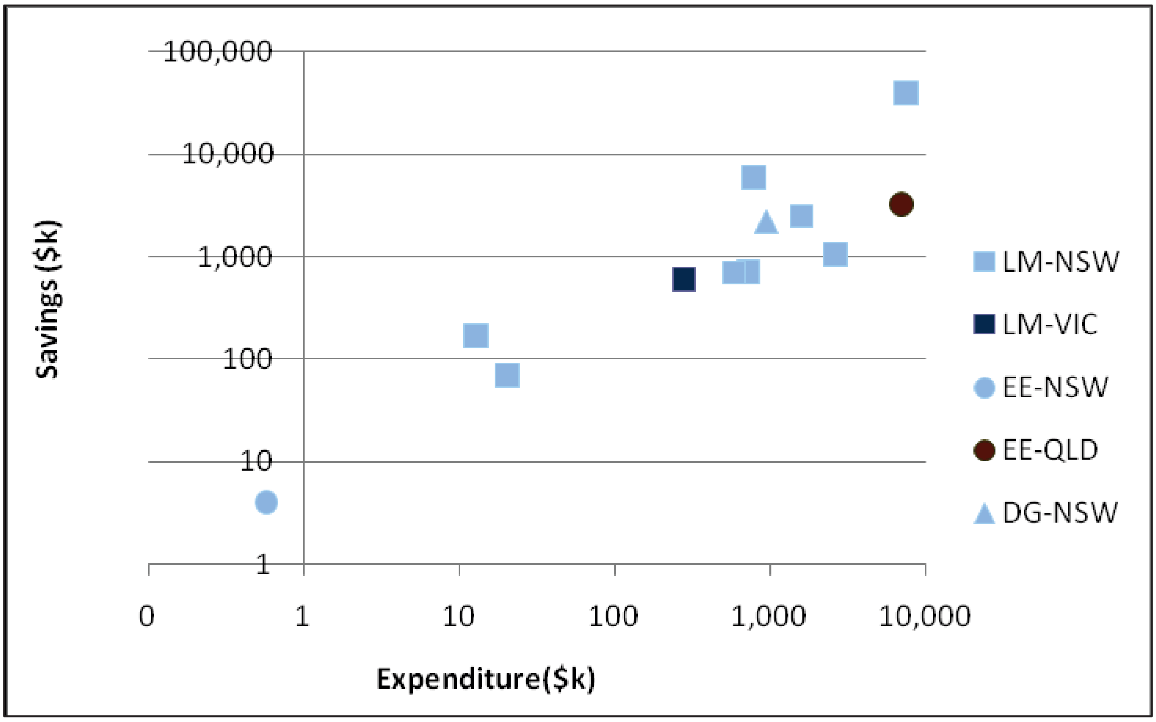


Figure 3-20 Savings vs. expenditure
(Dunstan et al., 2011d)

Some projects had costs or benefits measured in years other than those reported in 2008/09 to 2010/11. Additionally, some organisations did not provide data for each reporting year. This may have impacted some of the reported projects included in the cost benefit analysis.

3.5 Overall survey findings

The majority of reported electricity network DM projects implemented in Australia are in the area of peak load management. The goals of these peak demand projects are primarily peak load reduction, rather than energy savings, and so greenhouse gas emission savings are quite low.

An annual survey would be highly beneficial to increase the validity of the data and subsequent reports. Subsequent surveys could also take on suggestions for improvements of the survey, making the data collection more robust and less patchy. An annual survey could also set a precedent for reporting of future projects, to allow more relevant data to be collected. Additionally, the survey could be expanded to cover DM projects undertaken by electricity retailers, and where relevant, vertically-integrated utilities.

3.6 Further detail on survey

3.6.1 Sector and project types

Of the 115 projects reported, 26 were residential, 30 were commercial, 22 were industrial and 38 were mixed (nine of the mixed projects reported specifically as commercial/industrial mixes). The mixed projects were mostly locationally rather than sector-driven and were therefore harder to categorise by sector.

Most projects were reported as load management (LM) (97), and were broken down into nine categories as per Table 3-21. Six EE projects were reported as EE, in addition to some LM projects that have been categorised as EE. Of the projects for which DG data were reported, 12 were included as projects in this analysis, representing 12 data sets in the commercial or industrial sectors from ten NSPs.

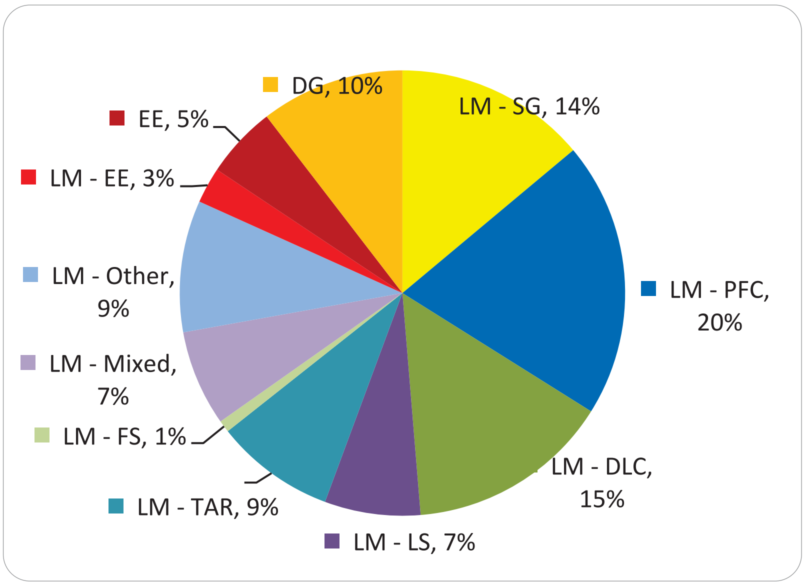


Figure 3-21 Breakdown of projects by type and technology

(Dunstan et al., 2011d)

(For explanation of the category labels, see Table 3-20 below.)

One-fifth of the projects implemented were power factor correction projects (23 projects, 20%), followed by standby generators (17, 15%). Three projects were reported as LM, but described as EE (denoted as LM-EE), and therefore nine (8%) projects were in the area of EE, and 12 (10%) in DG. Eight projects were described as mixed (7%).

Load management

The NSPs reported on a range of load management projects, summarised below.

Table 3-20 Number and types of load management projects

LM project type	Label	No. of projects
Power factor correction	PFC	23
Direct load control, including hot water, air conditioning and pool pumps	DLC	17
Stand-by generators for peak demand supply, including cogeneration and diesel	SG	16
Tariff trials, including time of use	TAR	10
Load shifting	LS	8
Commercial and residential energy efficiency projects	LM-EE	3
Fuel Switching	FS	1
Mixed projects, e.g. multiple elements used in a particular location	Mixed	8
Other	Other	11
Total		97

(Dunstan et al., 2011d)

Of the 97 reported LM projects, 60 reported peak demand reductions (kW), 28 reported energy savings (kWh), 36 reported expenditure data ($) and 31 reported cost savings data ($). Of these, no project had the full data set (i.e. kW, kWh, expenditure and savings reported for a single project).

Energy efficiency

The six energy efficiency projects included conversion of lighting to compact fluorescent lamps (CFLs) (3 projects) and improved hot water systems in the residential and small commercial markets (1), as well as mixed energy efficiency initiatives.

Distributed generation

A total of 84,853 distributed generators were reported by ten NSPs. The majority of the DG projects (84,780) were residential distributed generators, reported mostly as small-scale photovoltaics (PV), representing 174 MW (22%). An additional 64,000 applications for connection have been made to date, and their connection status is not known in all cases. A total of 624 MW was reported from 73 distributed generators in the commercial / industrial sectors, and contributing 78% of the distributed generation capacity. NSPs reported owning 2.9MW (3.7%) of DG, reported under commercially operated plant.

Data was not requested on individual DG projects, but was collected by sector for each NSP (e.g. the total number and capacity of distributed generators for the residential, commercial and industrial sectors in their networks). Because of the aggregated nature of the data, each group of data was analysed as a separate 'project' (e.g. all industrial generators reported for a given NSP), rather than for individual generators. This means that a DG 'project' may include multiple types and varying numbers of generators. Small-scale PV was not included in this 'project' analysis, but was included in the total numbers for DG.

Note that estimates of energy savings were reported for small-scale residential PV but were not included in the above analysis because NSPs do not generally influence system location and energy dispatch of small-scale residential PV, so they were not regarded as DM.

Time-of-use meters and tariffs

Of the five NSPs who reported on time-of-use metering assets, four indicated that they offered ToU tariffs on their meters. No NSPs provided energy savings or peak demand reduction data from these metering assets or tariffs. Anecdotally it was suggested that data on the effectiveness of ToU meters or tariffs on peak demand reduction is not currently measured or collected within NSPs.

3.6.2 Data robustness

Several NSPs are implementing multiple DM projects and are collecting valuable data. Each NSP reported data differently, so aggregated data may not give a true indication of the scale of the projects that have been undertaken to date. It is hoped that, should this survey become an annual event, more comparable data will be available on each reported project.

Each respondent had a different level of data available to report on DM projects. By way of explanation, a summary of the data available shows that of 115 projects, 66 reported expenditure associated with their projects, but only 38 reported cost savings. This does not mean there were no cost savings resulting from these projects, as the savings may not have been captured by internal reporting systems.

Table 3-21 Number of DM projects with relevant data

Technology type	Total no. of projects	No. of projects reporting expenditure ($)	No. of projects reporting savings ($)	No. of projects reporting peak demand reduction (kW)	No. of projects reporting energy savings (MWh)
LM	97	58	31	60	28
EE	6	4	4	4	5
DG	12	4	2	4	2
Total	115	66	38	68	36

(Dunstan et al., 2011d)

Respondents were requested to indicate whether their project data was measured, estimated or expected. The majority of project data was measured, with some also being estimated. All 2010/11 data was reported either as expected or estimated, as the reporting period had not yet been completed.

Table 3-22 Number of projects providing data as measured, estimated or expected

<table>
<tr><th></th><th>Data type</th><th>08/09</th><th>09/10</th><th>10/11</th></tr>
<tr><td rowspan="3">No. of projects reporting energy savings (MWh)</td><td>Measured</td><td>17</td><td>18</td><td>0</td></tr>
<tr><td>Estimated</td><td>3</td><td>3</td><td>2</td></tr>
<tr><td>Expected</td><td>0</td><td>0</td><td>16</td></tr>
<tr><td rowspan="3">Projects reporting peak demand reduction (kW)</td><td>Measured</td><td>27</td><td>32</td><td>1</td></tr>
<tr><td>Estimated</td><td>1</td><td>6</td><td>3</td></tr>
<tr><td>Expected</td><td>1</td><td>0</td><td>29</td></tr>
</table>

(Dunstan et al., 2011d)

Overall, this survey research has highlighted that electricity network DM in Australia is already delivering net benefits valued in the tens of millions of dollars per annum, despite the limited attention paid to this resource. This research also suggests that the potential value of network DM may be many times this value.

There is an urgent need to undertake regular, robust consistent reporting of activity in this area, in order to assist the development of cost-effective decentralised energy. This theme is revisited in Section 5.6.1 in relation to the barriers created by the lack of reliable, accessible information. Chapter 8 discusses policy tools to redress this information deficit, including proposals for consistent, consolidated, annual reporting of the outcomes, benefits and costs of network DM and other DM (see Recommendations S7, S8, G10 and N21).

Chapter 4. Network Costs and Mapping Demand Management Opportunities

4.1 Introduction: Why networks costs (and location) matter

To understand the value of demand management, it is important to recognise that there are two major components to electricity costs: locational costs and system-wide costs. The system-wide costs relate to the value of energy across the service territory and they reflect the cost of generation fuel and capacity and other costs associated with system security, market settlement and regulation. These system-wide costs can vary by time of year and time of day in response to changes in demand and supply conditions, but they are the same across the whole geographical area being served.

In contrast, locational costs are strongly associated with the cost of network infrastructure in particular parts of the service territory. Network costs are sometimes, to some extent, reflected in network charges that vary by time of day, but they are generally charged at a geographically uniform 'postage stamp' rate across the whole service territory. As shown in Figure 4-1, these locational network costs (distribution and transmission) are substantial and represent the majority of electricity supply costs in some Australian states.

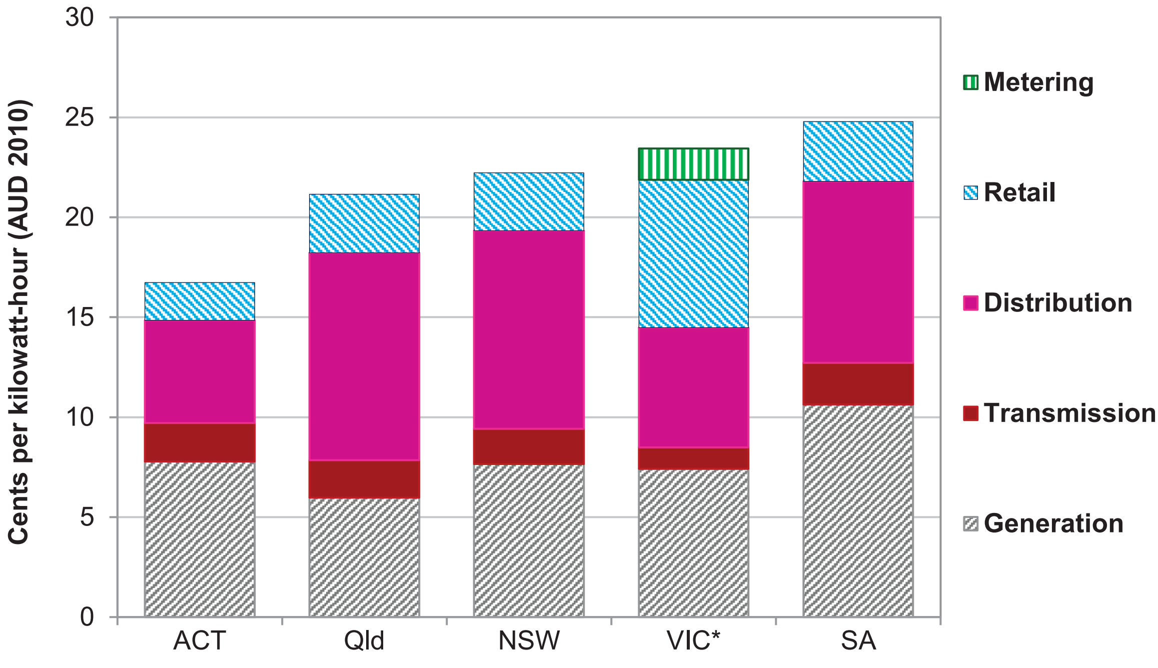


Figure 4-1 System-wide and locational costs of electricity supply in Australian states
(Dunstan, 2015a, p. 209)
(excludes carbon tax, goods and services tax and renewable energy and other market levies)

Policy makers and regulators are also being forced to re-evaluate how to support a resilient and efficient electricity system in the context of a shift towards variable output renewable energy and decentralised energy. In order for utilities, policy makers and regulators to respond effectively to these emerging technologies and trends, they need to recognise that this evolution involves more than simply replacing large-scale power stations with solar panels and batteries.

Unlike the centralised electricity industry, which involves a relatively small number of large generation and transmission equipment suppliers and highly regulated purchasers, the solar panel and battery industry is emerging as a complex consumer market with many sellers and buyers. The rise of decentralised energy means that managing networks must become a more collaborative process which involves network customers. This means that a satisfactory outcome will depend on efficient, cost-reflective prices and accessible, low-cost, accurate information.

As noted in Section 1.5.2, over the past ten years, the Australian electricity market has experienced unprecedented spending on electricity network infrastructure. Figure 4-2 illustrates the rise in network infrastructure spending between 2006 and 2015 for Australian states and territories. Planned network capital expenditure investment between 2010 and 2015 totalled more than $45 billion ($AUD2010) (Langham et al. 2010a).

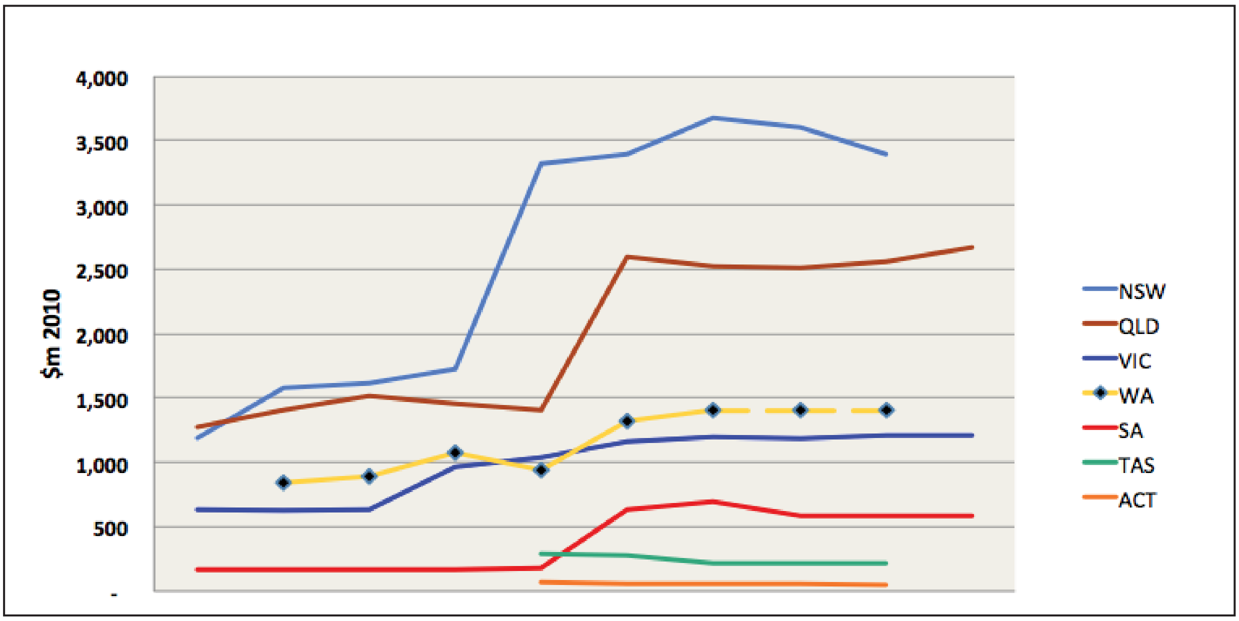


Figure 4-2 Electricity network capital expenditure by jurisdiction, 2006-2015

(Langham et al., 2011a)

Table 4-1 Electricity network-approved capex by jurisdiction (2010 to 2015 AU$2010)

	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**

(Langham et al., 2010a)

There were three main drivers for this boom in network investment: growth in peak electricity demand; higher reliability standards imposed by governments on electricity utilities; and replacement of ageing infrastructure. The growth in peak demand is far outstripping growth in average demand. This trend towards increasingly 'peaky' demand, shown in Figure 4-3 below, results in the need for more infrastructure to deliver each unit of electricity, meaning higher costs for electricity delivered from centralised power stations to end users.

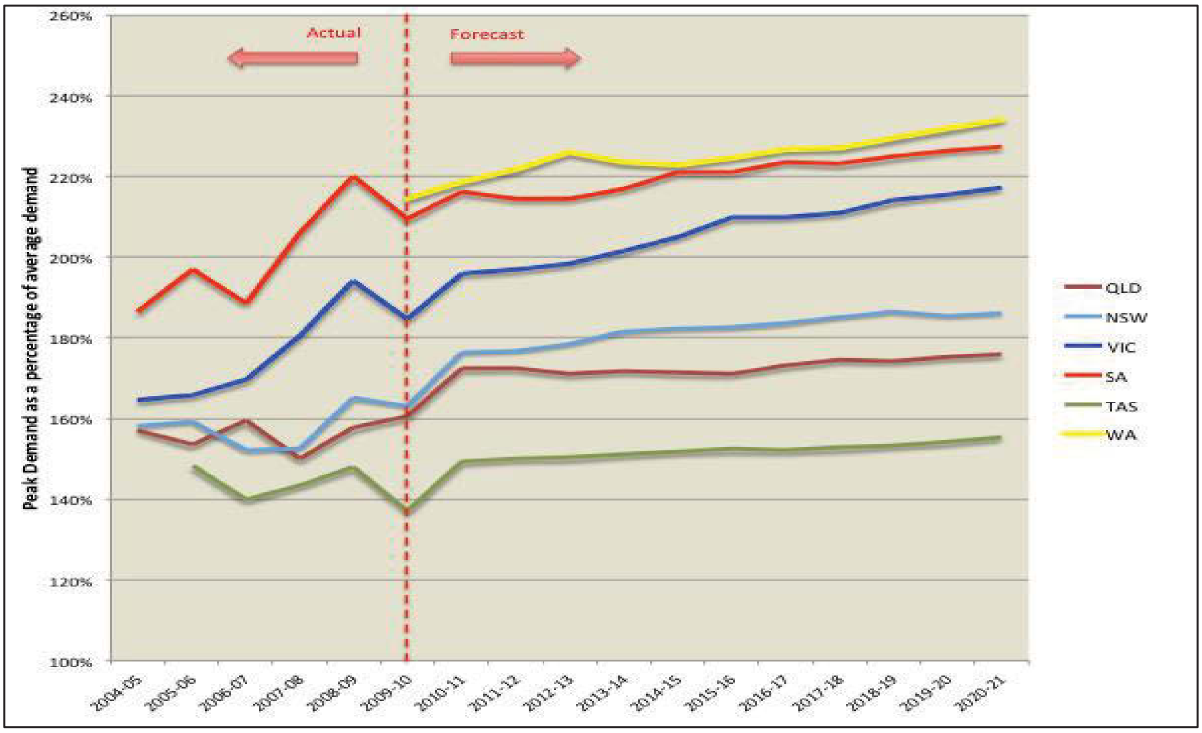


Figure 4-3 Peak Demand relative to average demand (by state, 2004-05 to 2020-21)

(Langham et al., 2010a, p. 21)

This additional investment has resulted in substantial increases in electricity prices in recent years. For example, electricity prices in the Sydney region rose by 105% between March 2007 and December 2014 (Australian Bureau of Statistics, 2014).[22] Of the 83% increase in power prices in the NEM between 2008/09 and 2013/14, more than two-thirds was due to increased network charges (Dunstan and Langham, 2010). Of the $45 billion in planned network capital expenditure between 2009/10 and 2014/15, almost one-third was directed towards meeting rising peak demand (Langham and Dunstan 2011). Given the capacity of decentralised energy options to reduce demand on electricity networks, much of this pool of investment could have been avoided by demand management, and this would have significantly moderated electricity prices rises.

Network cost analysis has traditionally been applied on a long-term average cost basis and/or a geographically averaged basis. The application of localised, marginal cost analysis is relatively rare. While market-based and/or administratively set ‘nodal pricing’ has been advocated, and in some cases applied, the effectiveness, practicality and equity of this approach have been contested (Sotkiewicz 2006; Green 2006; Oren et al. 1995). A practical variant on nodal pricing based on marginal avoidable network cost, information disclosure and market testing has been developed in Australia, through the NSW Demand Management Code of Practice[23] (NSW Department of Energy, Utilities and Sustainability, 2004) and subsequently the National Distribution Network Planning and Expansion Framework (AEMC, 2012c). However, this approach can only succeed if the market is able to access and respond to the opportunities in a timely and cost-efficient manner.

4.2 Network Opportunity Maps – a new tool to manage the DE transition

With the rapid rise in the deployment of variable output renewable energy, more dynamic information is required, and it needs to be tailored and used to reflect the specific circumstances in each part of the electricity grid. The economics of electricity supply can vary dramatically from place to place and from time to time, depending on whether there is a local surplus or constraint in supply capacity. Decentralised energy (including energy efficiency, solar PV, distributed energy storage and demand response) is often the least cost and most

[22] 105% increase (114.5-55.9)/55.9 : March 2007 –Dec 2014,

[23] I was involved in drafting this Code of Practice.

flexible means of responding to these local constraints and opportunities. To engage the market to respond to the opportunities created, localised information and incentive signals need to be provided.

The most accessible and effective way of presenting such geographically differentiated information is, of course, a map. This thesis introduces the mapping of network costs as a means of analysing and communicating avoidable network costs, and as a tool to help tap the major potential cost reduction opportunities described above.

The first step in doing this was to develop an analytical approach to estimating the cost of network investment that may be avoidable by demand management. My research then extends this analysis further with the Dynamic Avoidable Network Cost Evaluation (DANCE) model to develop time-varying (dynamic) maps of avoidable network costs in order to show the time, date, year and cost of anticipated network capacity constraints.

These maps show:

- the available supply capacity by network capacity
- the location of anticipated network constraints
- the proposed cost of network investment to address these constraints
- what share of these costs is potentially avoidable by, for example, DM
- how these costs are allocated over years, months and time of day.

In short, the maps show dynamic avoidable network costs and a range of related data. This analysis is not just important in informing and encouraging the DE market to respond to requests for proposals from the network businesses – it also provides a network cost allocation method, both for assessing the efficiency of network tariffs and for designing location-specific time-of-use pricing.

As noted in Chapter 2, decentralised energy in general and energy efficiency in particular is often cited as the biggest, cheapest and quickest way to cut energy-related carbon emissions, to lift energy productivity, to cut bills for energy users and to improve energy security (see for example, IEA 2014). However, in the context of stagnant or falling energy consumption, some have argued that efforts to raise energy efficiency should be wound back to avoid increasing electricity prices. In this context, locational network costs become even more important, as described below.

With rising demand, DE and in particular energy efficiency, can avoid or defer not just the operating cost of generating power, but also the capital cost of power stations and the network infrastructure to deliver it. In Australia, these capital costs represent about 75% of the retail price of electricity (see Figure 4-1). However, falling demand significantly changes the economics of energy efficiency, as untargeted DE may only avoid about one-quarter of the cost of supply, the variable cost component. Therefore, while a customer conserving a kilowatt-hour of energy may save say, 30 cents/kWh, only say, 7 cents/kWh of these costs, the variable costs, will actually be avoided. The remaining 23 cents/kWh of fixed costs will still be incurred as a 'sunk' cost of capital by the existing generators and network businesses. These costs must be either borne by the utility and its shareholders or passed on to the consumers through higher energy prices.

In order to ensure the efficient development of DE, it is important that it be deployed in the right place, at the right time and at the right price. Given that DE depends on local circumstances, it is crucial that relevant information is available, both to utilities seeking to procure it and to providers of DE products and services.

In recent years, there have been stronger regulatory requirements on network businesses to consider 'non-network alternatives' and 'network demand management' in order to use DE as a more cost-effective option. However, the absence of clear, easily accessible data about network constraints, costs and potentially avoidable investment has been a major obstacle to the development of DE projects. Consequently, relatively few DE projects have been deployed relative to the scale of network investment and this has contributed to higher electricity bills (Dunstan et al., 2011d).

While network businesses in Australia now annually report capacity, demand and proposed investment data, this information is often difficult to access and interpret for those without specialised skills. The information is produced in different formats across the NEM and often lacks sufficient geographical and potential value of network support data to be useful from a customer's or a DE proponent's perspective.

The Network Opportunity Maps project, which developed out of my doctoral research, aims to develop and provide free, annually updated, online maps across the Australian National Electricity Market (NEM)[24] for:

- available network capacity (network constraints)
- planned network investment
- potential avoidable network costs.

The network opportunity maps provide clear, consistent and timely information on network opportunities and constraints to develop collaboration between networks, customers and DE project developers. They allow network businesses and their customers, and the proponents of non-network DE alternatives, to anticipate future network constraints in different parts of the network. They also make it possible for these stakeholders to develop a common understanding of the costs associated with additional loads and constraints, and of where and when DE can be most cost-effective.[25]

The network opportunity maps help DE providers to work with network businesses to reduce the need for new grid infrastructure and to lower electricity bills. By making clear the economic value of decentralised energy in each part of the grid, they also help network businesses who are seeking to develop innovative offerings to make the case to their regulators for investing in DE as a cost-effective alternative to investing in network infrastructure.

4.3 Quantifying network opportunities for decentralised energy

In order to map the local network opportunities for decentralised energy, it is first necessary to quantify their value. To do this requires several steps as outlined below:

1. Identify the need for additional network capacity in the locality.

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[24] The NEM encompasses the jurisdictions of Queensland, NSW, Victoria, South Australia, Tasmania and the Australian Capital Territory and stretches more than 4000 km from north to south. The NEM covers a geographical area roughly equal to that of France, Spain, Germany and the UK combined.

[25] The Network Opportunity Maps Project was led by the Institute for Sustainable Futures (ISF) at the University of Technology Sydney and received assistance under the Australian Renewable Energy Agency (ARENA) Emerging Renewables Program, the NSW Government and Queensland electricity distribution network business, Ergon Energy.

2. Quantify the amount of additional network capacity required – normally measured in kVA.
3. Clarify when the additional capacity is required, in which year(s), in which seasons and at what time of day. (This allows mapping of the available capacity.)
4. Estimate the cost of additional network investment. (This allows mapping of proposed investment.)
5. Estimate the annualised value of deferring this investment. (This allows mapping of the avoidable network cost, normally in dollars per kVA/year, and for the peak day, in dollars/kWh.)

Each of these steps is outlined below. For the purposes of illustrating the approach of this project, this chapter draws on images from an application of the DANCE model in 2011 to create network opportunity maps for the state of Victoria.[26]

4.3.1 Identify the need for additional local network capacity

Possible drivers for new network investment include:

1. to meet increasing demand
2. to replace ageing infrastructure
3. to improve reliability
4. to improve quality of supply
5. to improve safety.

Over the past decade, the first three of these have been the drivers for the large majority of network investment in Australia (Langham et al. 2010a). For decades, demonstrating a need for additional network capacity in Australia led directly to investing in network infrastructure to provide this capacity. This focus on building network infrastructure reached unprecedented levels in the past ten years when network capital expenditure doubled to about AU$9 billion

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[26] This version of the DANCE model can be accessed via this site: https://www.uts.edu.au/research-and-teaching/our-research/institute-sustainable-futures/news/decentralised-energy-victoria

per annum (Langham et al. 2010a), which in turn was the key contributor to electricity prices doubling between 2007 and 2014 (AEMC, 2013).

4.3.2 Mapping forecast available network capacity

In order to manage an electricity grid, it is essential for a network operator to have a clear understanding of both the network capacity and the forecast demand. When demand is forecast to exceed current capacity, this threatens the reliability of supply and new capacity is required. The traditional approach is to build new network capacity to meet forecast demand; however, new DE capacity can also address a shortfall in capacity by reducing demand to within existing capacity. There are many characteristics of capacity of the network (including voltage, reactive power, fault current etc.) but the most fundamental is the real power capacity, measured in volt-amperes (VA).

The forecast available capacity in each part of the network can then be calculated by using the following simple formula:

$$\text{forecast available capacity} = \text{current network capacity} - \text{forecast max. demand}$$

If forecast available capacity is negative, this indicates there is a shortfall and therefore additional capacity is required.

As noted above, in Australia, network businesses are required to publish such network capacity and forecast demand data annually. Using the DANCE model, this data is then mapped. An example of these maps is shown in Figure 4-4. Presented using a Google Earth platform, this map shows the available capacity of distribution network zones for the metropolitan area of the City of Melbourne, Victoria (Langham et al. 2011). Areas with forecast surplus capacity are shown in green while those facing a capacity shortfall are illustrated in red.

By calculating the forecast available capacity for a series of forecast years, a dynamic map is created that illustrates emerging network constraints over time. Based on network capacity in 2010 and forecast demand for each year from 2011 to 2015, it shows how, from year to year, more and more distribution zones become capacity constrained. Constrained areas are those where DE has the potential to relieve a network constraint. However, whether DE can in practice provide a more cost-effective solution to the network constraint relative to network augmentation depends on its technical characteristics and on the relative cost. The next section considers the question of relative costs for DM and network-based solutions to emerging network constraints.

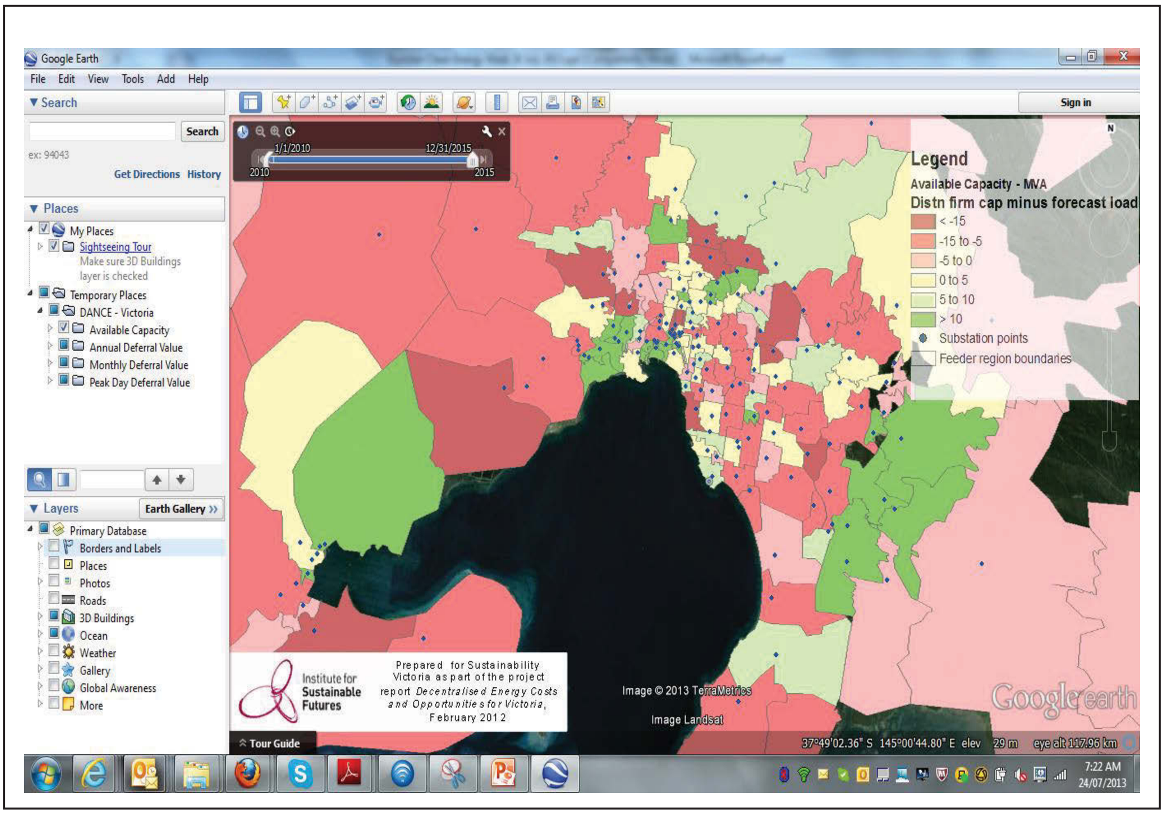


Figure 4-4 Available network capacity (MVA) for metropolitan Melbourne 2015 (Dunstan, 2015)

4.3.3 Quantify proposed additional network investment

Mapping proposed network investment is relatively straightforward, as it essentially consists of transposing investments onto maps, as illustrated in Figure 4-5. These maps indicate, not just where network investment is proposed, but also the scale of the investment (the larger the dot, the higher the cost of network investment) and the expected timing of investment (red dots indicate imminent investment while green dots are for later years).

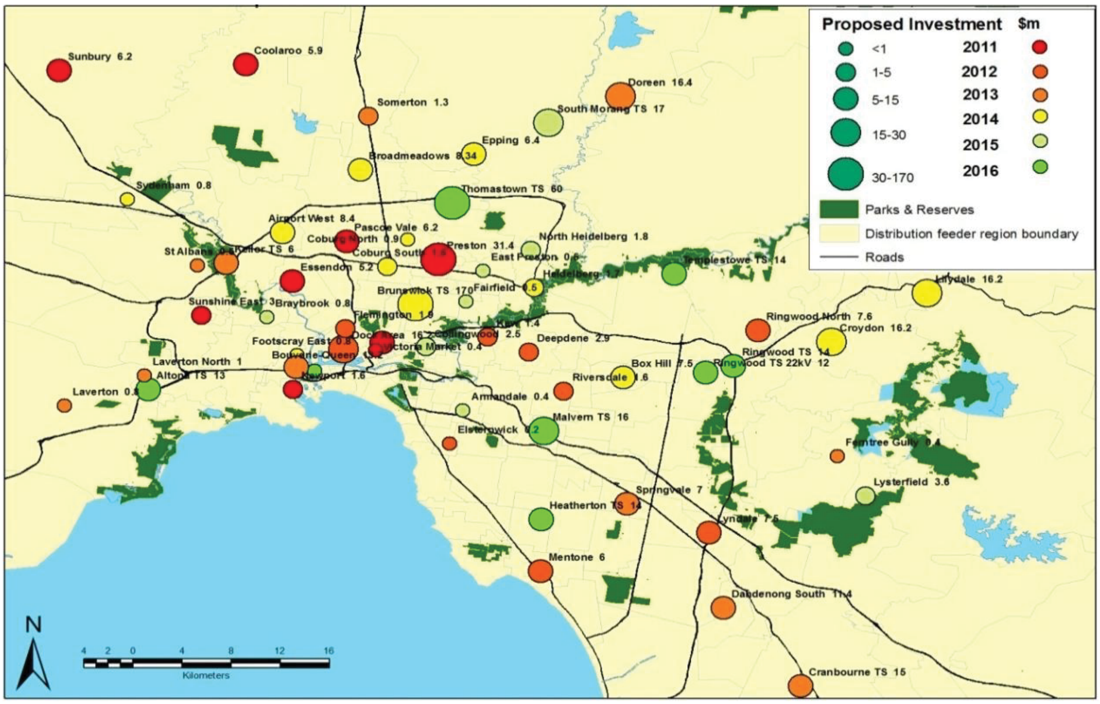


Figure 4-5 Proposed network investment in Greater Melbourne (2011-2016)
(Dunstan, 2015)

4.3.4 Estimate annual deferral value of investment

As noted above, it is not appropriate to simply compare the total cost of network augmentation with the cost of DE. One of the advantages of DE is that it is generally much more modular that network infrastructure. By contrast, network infrastructure tends to be 'lumpy', that is, it is generally installed in high-cost, large-capacity increments. This means that compared to network infrastructure, DE carries less forecast risk for the network businesses. For example, in the case of DE, if forecast demand does not eventuate, this does not matter as much because a much smaller investment cost has been incurred.

So, as DE tends to cost less per unit than network infrastructure, but provides less network capacity per unit procured, it is necessary to bring the two resource types onto a comparable basis. One approach is simply to divide the cost of the resource by the capacity provided. However, this approach is not equitable as it not only disregards the potentially lower risk profile of DE, it also disregards the fact that DE can provide capacity more in line with when it is needed. For example, a new zone substation transformer may provide plenty of capacity at relatively low unit cost. But if most of that capacity is not needed for many years, and the total cost is incurred now, then it may still be an expensive option compared to DE.

A more equitable approach is to compare the cost of DE to the deferral value of the network option. For example, if by investing in DE the network investment can be deferred by one year, then the savings achieved are equal to the annual financing cost of the investment plus the avoided depreciation of the asset.[27] To compare this to the DE option, it is necessary to divide by the additional capacity required to achieve the year's deferral. (For growth-related investment, the additional required capacity is typically the annual growth in peak demand.) In other words, the annual deferral value is:

$$\text{annual deferral value} = \frac{\text{proposed investment} * (\text{wacc} + \text{deprieciaton rate})}{\text{network capacity required}}$$

where:

Proposed investment is the forecast capital cost of additional network capacity ($)

WACC is the Weighted Average Cost of Capital for the network business (% p.a.)

Depreciation rate is the rate of depreciation of the new network asset (% p.a.)

Network capacity required is the annual growth in peak demand (kVA p.a.)[28]

Once these values have been calculated for each distribution zone of the network, it is possible to map the annual deferral values, as shown in Figure 4-7. In this map, the zones with the higher deferral value are shown in darker tones and those with lower annual deferral values are shown in lighter tones. As in the earlier capacity maps, the image here is a static screenshot from a dynamic multi-year map which shows how the annual deferral value changes over time. As the years pass in the map, the network constraint approaches, and the value of deferral gradually increases due to the diminished discounting of more imminent costs. However, once the commitment year for the investment arrives, the network investment is taken to be 'sunk', so the annual deferral value drops to zero as the cost is no longer deferrable.

The following discussion illustrates the potential range of avoidable network costs. In a competitive market, the price of goods will be expected to gravitate towards the marginal cost of the next-most viable source of supply. In electricity networks, this marginal cost of supplying additional capacity, at a given location, can be defined as the incremental increase in

[27] In addition, there is an additional operation and maintenance cost associated with the new asset, but as new asset can sometimes reduce O&M on existing assets this additional cost is not included here.
[28] Note that this formula applies for peak demand growth-related investment. For network augmentation associated with other drivers the denominator will need to be adjusted accordingly.

network costs per unit increase in peak demand required to be carried by the network (Equation 1). The average network cost is the total network cost per unit of total network peak demand (Equation 2).

$$\text{marginal cost of supply (\$/kVAyr)} = \frac{\text{incremental annual network cost (\$/yr)}}{\text{incremental increase in peak demand (kVA)}} \quad \text{(Eq'n 1)}$$

$$\text{average cost of supply (\$/kVAyr)} = \frac{\text{annual network cost (\$/yr)}}{\text{peak demand (kVA)}} \quad \text{(Eq'n 2)}$$

The marginal cost of supply looks forward to the next investment required to satisfy increasing peak demand in a specific location. In contrast, the average cost of supply looks at past investment for existing demand.

Figure 4-6 illustrates an example comparison between the average cost of supplying network services to residential and business customers in NSW, with the marginal cost of supplying additional network services in four Sydney distribution zones. These costs have been calculated from future investment estimates and demand growth data available from NSW electricity network service providers (Energy Australia, 2004; Integral Energy, 2004).

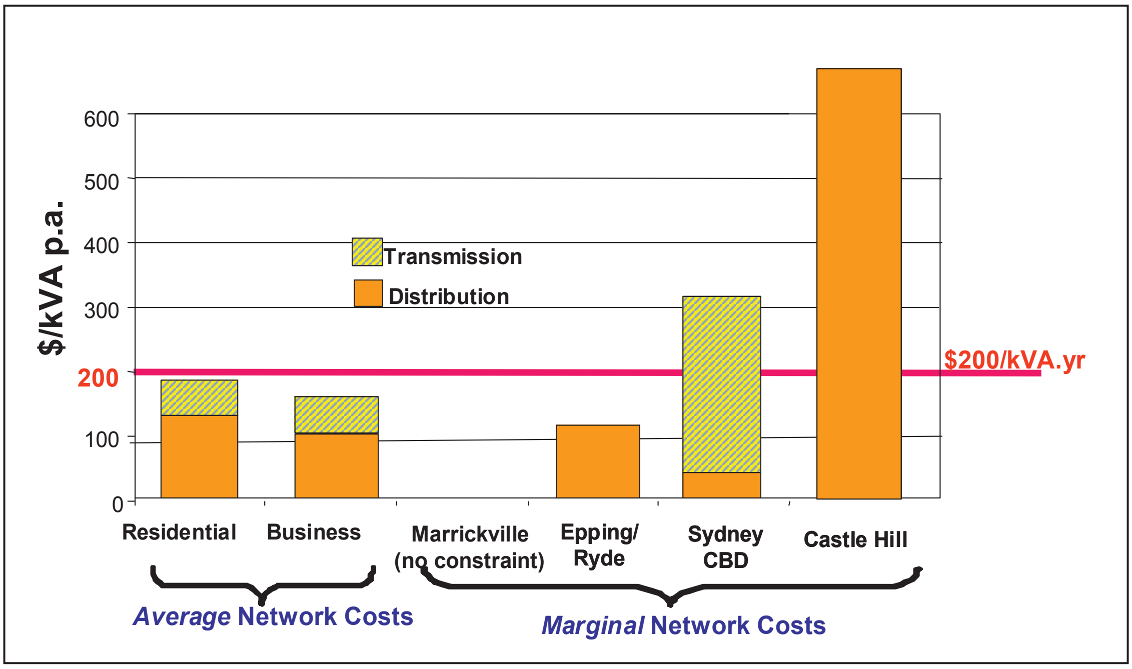


Figure 4-6 Average and marginal cost of network capacity in four Sydney substations (Dunstan, 2007)

In this example, the Marrickville substation does not currently face a network constraint. Consequently, no investment is warranted and the marginal cost of supply is zero. In contrast, there ***is*** a constraint in Castle Hill requiring substantial investment. This investment will increase the annual network cost and furthermore, in the first year after firm network capacity is exceeded, the required quantity of additional capacity (over which the investment deferral is spread) is small. Consequently, the value of avoiding or deferring each kVA of additional capacity is large. In this case it is over $600/kVA per year.

This calculation can be done for each area of the electricity grid and then mapped, as shown in Figure 4-7, annual deferral values range from zero to more than $1000/kVA per year. By comparison, network charges in Australia average about $250/kVA per year. There are likely to be very significant DE opportunities that could be deployed for less than this deferral value.

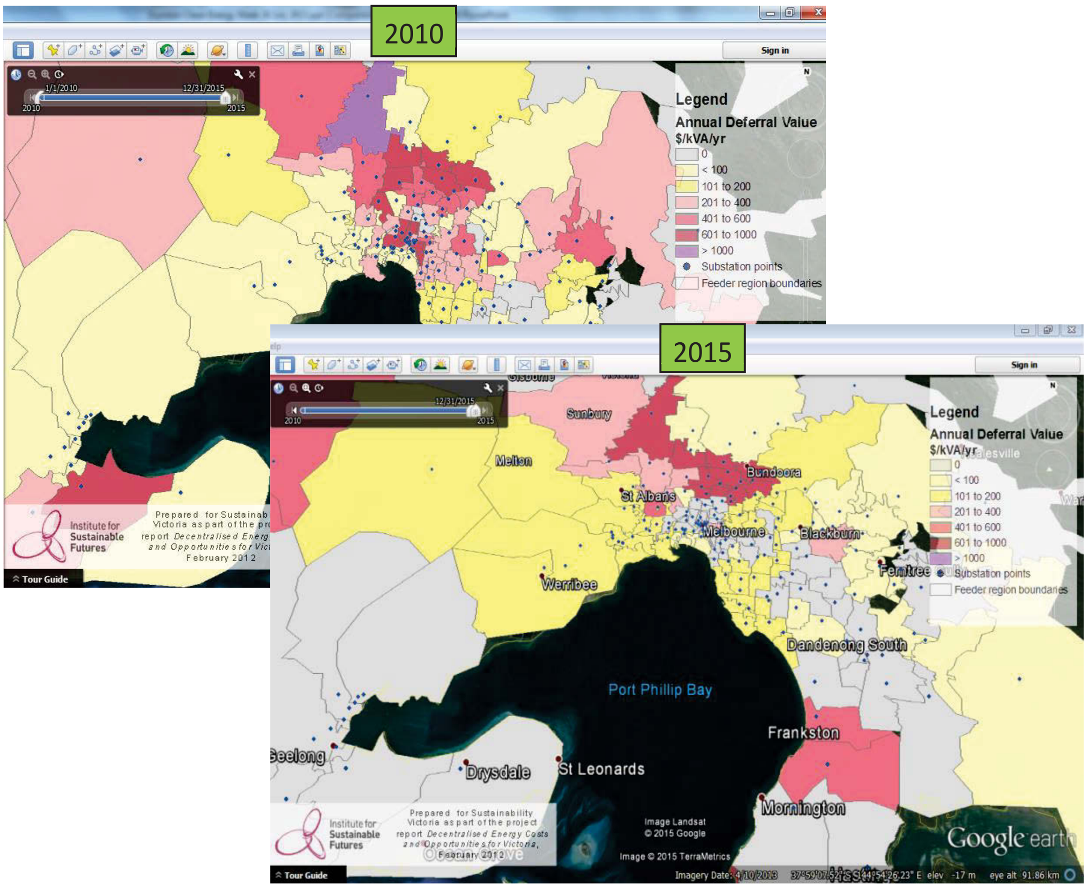


Figure 4-7 Annual marginal deferral value for 2010 (top left) and 2015 (bottom right) (Dunstan, 2015)

4.3.5 Estimate the hourly deferral value

Customers and DE providers are generally unfamiliar with $/kVA per year as a unit of value in the electricity sector. To highlight what this could mean in units that are more familiar, it is useful to consider what this value would be worth in $/kWh. This value can be easily estimated by dividing the annual deferral value by the number hours in which demand is expected to exceed the current network capacity by any given amount of kVA.

For example, if the annual deferral value is $800/kVA per year, and the forecast demand is expected to exceed the current capacity by 1 kVA for a period of four hours, then the hourly deferral value for those four hours is $800/kVA/year divided by 4 kVA.hour per year, which equals $200/kVA.hour, which approximates to $200/kWh. By comparison, the average price of electricity in Australia is about $0.30/kWh. So the hourly deferral in this case would be about 600 times the average retail electricity price. While this is a high value, it should also be noted that in this case this value only applies for the four hours when demand exceeds current capacity. On the other hand, if the deferral value extends over several MVA of required capacity over several peak days and a series of years of network investment deferral, then this could amount to a significant value stream for DE.

The same calculation can be performed for every kVA and every hour that demand is forecast to exceed current capacity. This approach is illustrated in Figure 4-8. This figure has ‘zoomed in’ from a metropolitan-wide perspective to focus on the central business district of Melbourne and in particular the Flinders-Ramsden distribution network zone. The transparency of the avoidable network value layer has been increased to show the roads, watercourses and other underlying geographic features.

The white ‘pop-up box’ shows several features of the zone including the hourly deferral value on the peak day, which in this case is in summer. Also indicated is that for most of the day, the hourly deferral value is zero, but between the hours of 1 pm and 6 pm the hourly deferral value rises to a maximum of $648.70 per kWh.

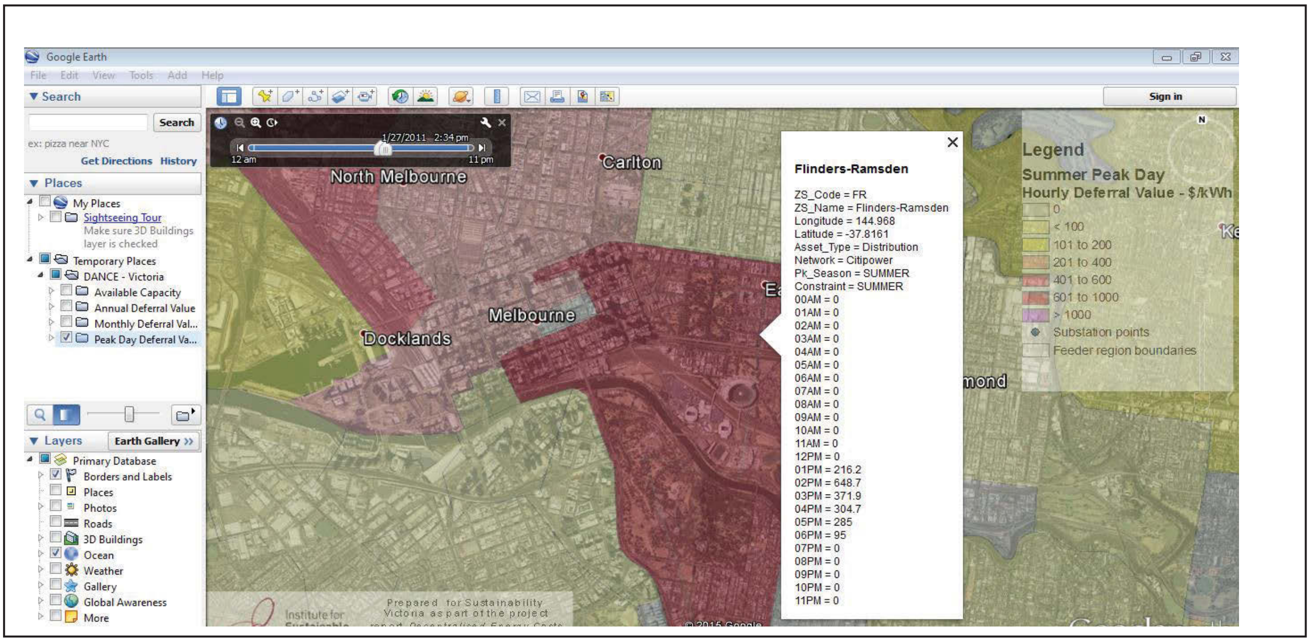


Figure 4-8 Hourly deferral value on summer peak day, central Melbourne in 2010 (Dunstan, 2015)

Figure 4-9 below explains graphically this process of calculating hourly deferral values. 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 4-9 is for a particular hour of the day at which the demand is around 13,900 MVA. This demand is above the firm capacity of 13,600 MVA and thus a constraint occurs. According to the Load Duration Curve, this level of demand is reached for only three hours per year, and from the earlier annual deferral value calculation we know that this constraint carries a value of $600/kVA/yr.

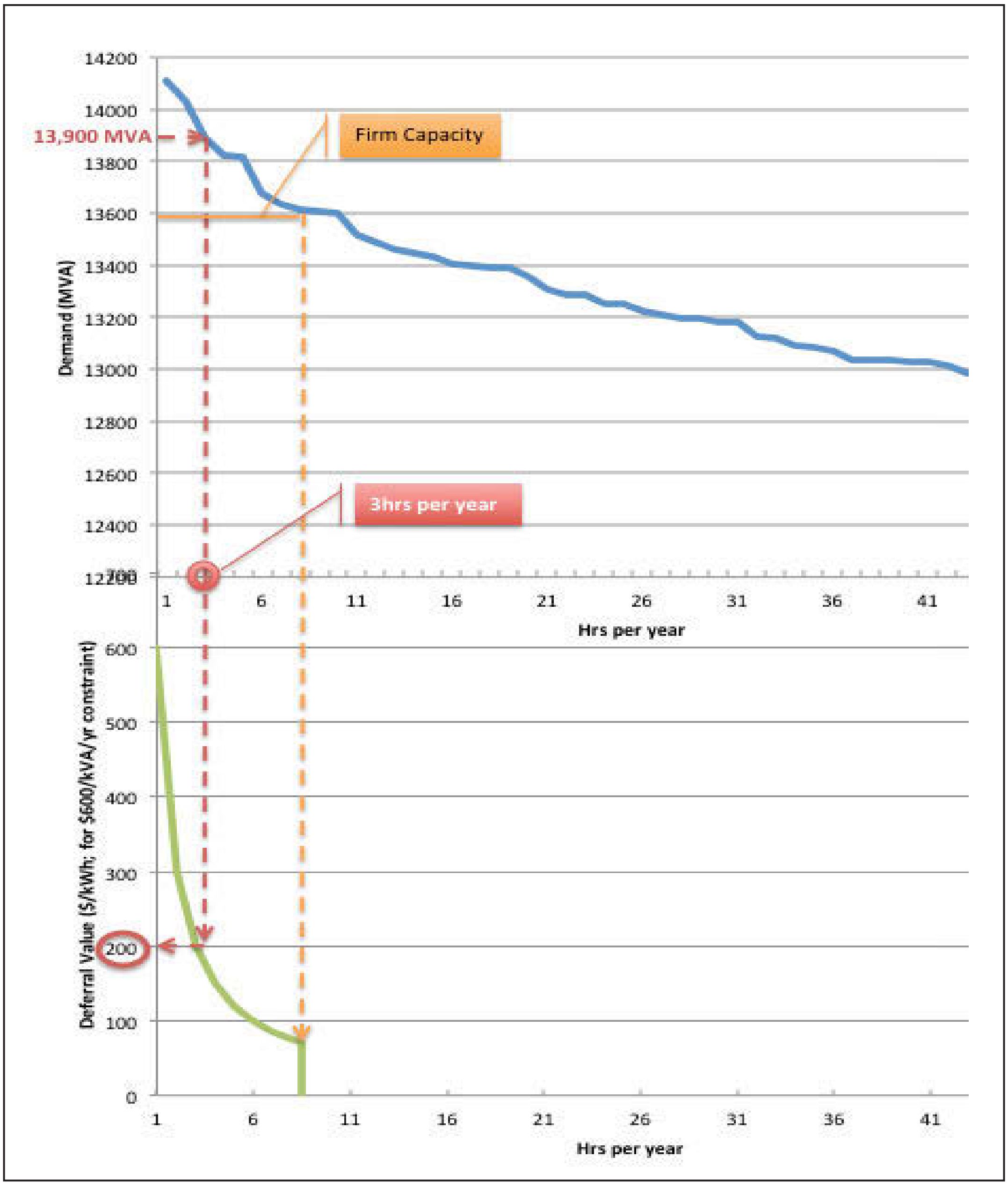


Figure 4-9 Graphical depiction of hourly deferral value calculation

(Dunstan et al, 2012)

Reading the corresponding value for three 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 hours before and 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 firm capacity is no longer exceeded, as indicated by the orange dotted line in Figure 4-9.

As shown in Figure 4-8, Network Opportunity Maps can provide a wealth of additional information embedded in them. By clicking on each zone on such a map, users are able to see a range of other details including details of current capacity, forecast demand, proposed investment at different network levels within the grid, network business, season of constraint, and so on.

4.3.6 Case study

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 consider a case study of a representative distribution zone substation. Using network data from 2015, Caringbah Zone Substation in suburban Sydney 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 in Section 4.3.4 are highlighted in Table 4-2 below, which shows the separate calculations of distribution and transmission deferral values after factoring in investment values and annual load growth.

Table 4-2 Case study – annual deferral value at Caringbah Zone Substation

Proposed Investment (Distribution):	$3 million
Distribution Annual Deferral Value ($/yr)	8.8%[29] 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
Total Annual Deferral Value (Distrib'n + Transm'n)	**$1,728/kVA/yr**

(Dunstan et al. 2012)

Figure 4-10 shows, for Caringbah Zone Substation, how the load on the peak day relates to the firm capacity of the substation, and the hourly deferral value. 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 between 3 pm and 7 pm (the green load curve line, using the scale on the right-hand side). With a firm capacity of around 30 MVA (dotted red line), this level is exceeded for a period of six hours, from 1 pm to 7 pm. As the magnitude of the exceedance increases, so too does the marginal deferral value per kilowatt hour, as higher demands occur for a shorter period of time. To illustrate, by taking a value of $1,728/kVA/yr and spreading this across the hours of the year in which firm capacity is exceeded, the peak value reached in the single highest hour is $1,728/kWh. As shown in

[29] 8.8% WACC used by the AER in the NSW distribution network regulatory decision.

Figure 4-10 below, this occurs at 4 pm. This is shown graphically as the purple area (indicating a deferral value greater than $1000/kVA/year) at the top of the 4 pm column, which corresponds to the purple in the 4 pm map for the Caringbah distribution zone in the hourly charts, as shown in the 4 pm image connected by the red arrow.

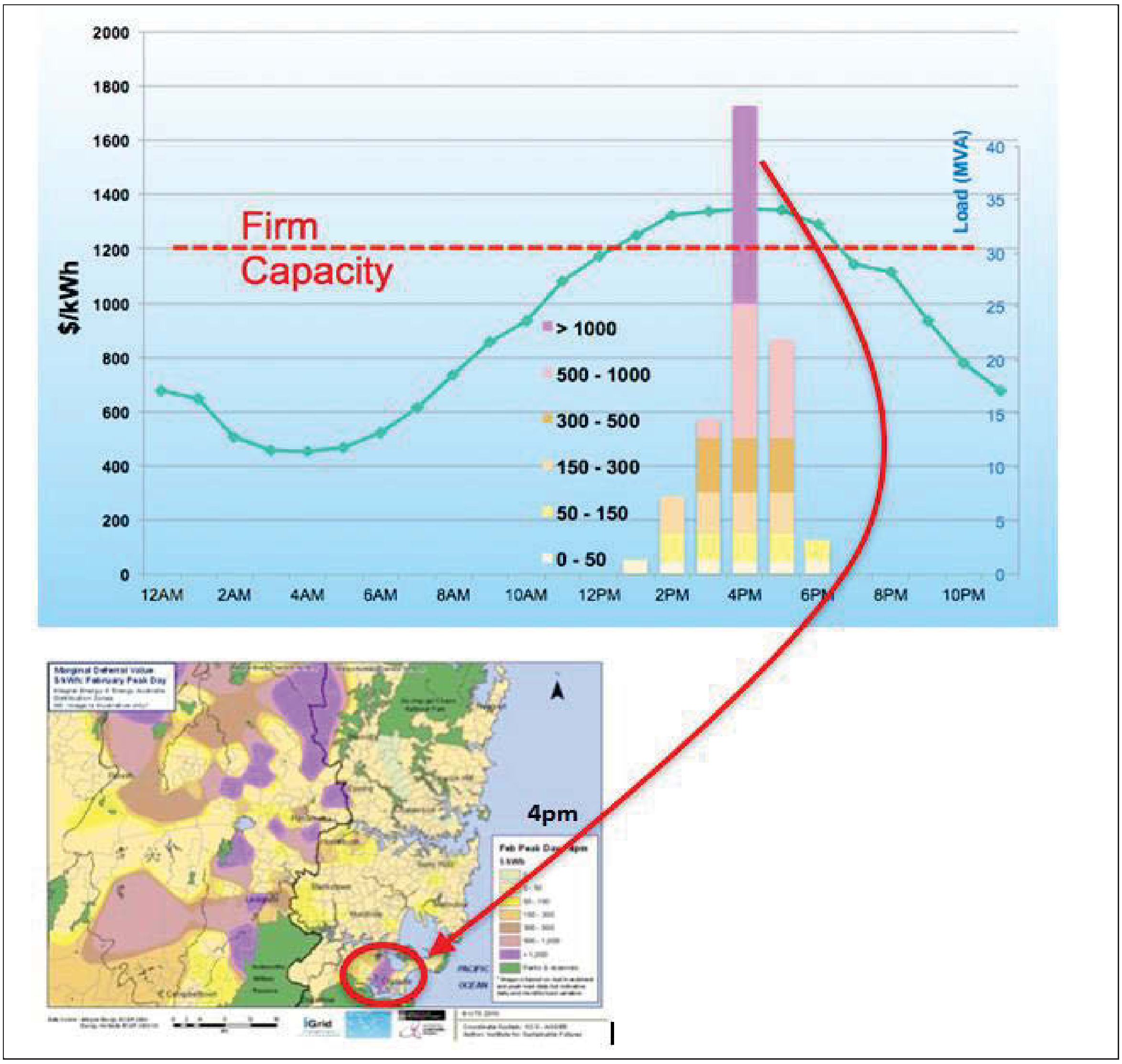


Figure 4-10 Case study – Caringbah zone substation deferral value on peak February day (Dunstan et al. 2012)

4.4 Using the Network Opportunity Maps

The ultimate test of the value of the Network Opportunity Maps is the extent to which they lead to greater adoption of DE (including energy efficiency, peak load management and distributed generation). This depends on the extent to which they are used. This section describes how the maps could be used by DE providers, network businesses, policy makers and regulators to create value.

4.4.1 DE providers

The Network Opportunity Maps are likely to assist DE product and service providers by:

- informing them, up to several years in advance, of where network constraints and potential DE market opportunities are expected to emerge
- giving them an indication of the scale, duration and timing of the DE market opportunities
- giving them an indication of the likely value of DE opportunities
- providing them with useful information to assist in discussions with network businesses about providing network support
- helping them to engage with customers to develop DE offerings that will be of interest to customers and network businesses.

4.4.2 Network businesses

As Network Opportunity Maps are based on the locational network capacity and value, network businesses are essentially intermediaries to realising DE value. The data on which Network Opportunity Maps are based derives from the network business, and capturing the value depends on avoiding the cost of network infrastructure spending and redirecting some of these savings towards supporting DE instead. Network Opportunity Maps can assist the network businesses by:

- informing and building the DE market (while providing better information about the capacity of DE providers to deliver)
- attracting early interest from DE providers to assist network businesses in developing non-network business plans
- assisting network businesses in making the business case to their regulators for undertaking DM instead investing in more network capacity
- helping network businesses to expand into new business areas that can deliver lower costs to consumers and higher returns to shareholders.

4.4.3 Policy makers and regulators

DE has long been recognised as having the potential to reduce cost to consumers, while creating net growth in local employment and cutting carbon emissions and other pollutants. The Network Opportunity Maps have the potential to expedite these objectives that policy makers and regulators share. In particular, the Network Opportunity Maps have potential to assist these stakeholders by:

- deepening and broadening the market for cost-effective DE options
- creating more choice for energy users
- reducing energy costs to consumers
- supporting economic expansion in the fast growth, high value added, low carbon DE sectors.

It should also be noted that while the main focus of the Network Opportunity Maps to date has been on providing alternatives to network augmentation driven by growth in peak demand, they also have great potential to be applied to a range of other drivers of network investment, including: replacing aged assets, improving reliability, voltage and power quality management, and even asset retirement.

4.4.4 What about pricing? Locational cost-reflective pricing

It is evident from the above discussion that electricity pricing based on the marginal locational cost of supply would provide a strong signal for investment in extra capacity, or for reductions in demand in localities approaching supply capacity. This would provide a better basis for sourcing competitive solutions from either DM or traditional network asset investments.

However, pricing electricity solely on volatile, locational short-run cost could discourage business investment and could create real or perceived social equity problems. For example, the competitiveness of businesses could be influenced by changing electricity prices as a network approaches capacity constraints. Full locational pricing is also likely to be costly to implement in billing systems.

Alternatively, pricing based on the average network cost of supply provides a stable return for investment in long-term assets. Unfortunately, an approach based on the average cost of supply can lead to the cost of supply, and therefore prices, steadily decreasing as consumption approaches capacity limits (because the required return on historic investment is smeared over a larger volume of traded electricity). It may then require an external intervention to kick start new investment in capacity. This is not conducive to competitive sourcing of cost-effective DM solutions.

Applying the principles of least cost planning has the potential to help reconcile these competing pressures. One such approach is through a ‘nodal auction model’ of network pricing to signal and manage local network congestion and support investment in new capacity in both networks and decentralised energy resources (Outhred and Kaye, 1994).

Efficient regulation requires an approach that (i) balances the need for stable returns for large network investments in base load electricity distribution, and (ii) provides signals for competitive investment in alternative capacity solutions.

4.5 The evolution of network opportunity maps and the DANCE model

I developed the DANCE model in collaboration with colleagues at Institute for Sustainable Futures (ISF), between 2008 and 2011, by drawing on my previous research (incl. Dunstan and White, 2009). This version of the model was used for several one-off projects for mapping metropolitan Sydney, metropolitan Melbourne, and rural areas of the NEM suitable for concentrating solar power (Langham et al., 2011a; Langham et al. 2012; Rutovitz et al. 2013). These previous DANCE versions involved highly time-consuming manual processes, and the information became quickly out of date. Producing updates in the same manner would be inefficient and expensive. The Network Opportunity Mapping project described below transcends these past projects by setting up a structure for consistent, regular, NEM-wide maps.

The three year Network Opportunity Maps project has developed a key resource for developing collaboration between networks, customers and decentralised energy service providers. The project involved all 18 electricity network business in the NEM, policy makers, regulators and clean energy companies to develop free, annually updated, online maps of network constraints, planned investment and the potential avoidable costs across the Australian National Electricity Market. The maps provide clear, consistent and timely information on network opportunities and constraints for DE and demand management project proponents.

The network opportunity maps help decentralised energy service providers to work with network business to anticipate future network constraints, reduce the need for new grid infrastructure and lower electricity bills. These maps should enable faster development of decentralised energy and demand management by showing where and when such resources can be most cost effective.

The first sample national maps for the Network Opportunity Maps project were published in 2015. The network opportunity maps project was finalised in October 2017 and Energy Networks Australia accepted responsibility for hosting the maps. The new network opportunity maps are available at: http://www.energynetworks.com.au/network-opportunity-maps .

A screenshot of the current network opportunity maps is shown in Figure 4-11.

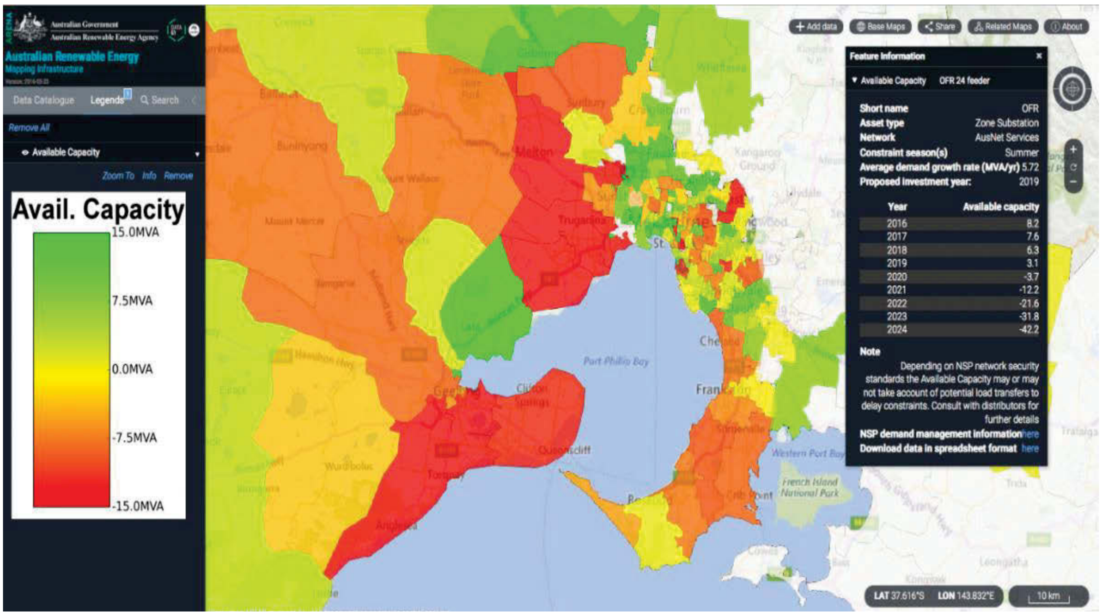


Figure 4-11 A screenshot from the Network Opportunity Maps showing Available Capacity (Institute for Sustainable Futures, 2017)

4.6 Collaboration to develop the Network Opportunity Maps

Reflecting the changing nature of the electricity industry, the Network Opportunity Maps are innovative, not just in their content and how they are intended to be applied, but also in the way they are being developed. Just as the use of the Network Opportunity Maps is likely to involve an unprecedented level of collaboration and engagement between network businesses, DE providers, customers and regulators, so too the Network Opportunity Map project was developed on a collaborative basis by these stakeholders

ISF has worked with network businesses across the NEM to develop a clear, standardised data protocol to populate an annually updated, publicly available mapping resource. This three-year project has allowed for time to engage with network businesses and regulators and work through methodological considerations. The project involved six key tasks:

- consultation with all NSPs to refine the methodology, inputs and outputs
- development of a robust data protocol
- model and platform development
- mapping iterations
- broader stakeholder engagement, including policy makers, regulators and DE proponents
- identification of a host organisation for subsequent annual updates.

4.7 Policy and regulatory implications

The Network Opportunity Maps allow network businesses and other stakeholders to see more clearly where DE can provide a more cost-effective option than network augmentation. However, this does not necessarily mean that DE options will be adopted. There are two interrelated factors that hold the key to the adoption of cost-effective DE: firstly, the willingness of the network business to develop a DE business in parallel with, and to some extent in place of, their traditional network management business; and secondly, the willingness of regulators to remove barriers which discourage NSPs from providing such services.

A key issue for the network regulators is their perception of competitive neutrality. For example, electricity network businesses are normally regarded as natural monopolies. There is therefore, on the part of regulators, an understandable wariness about allowing a monopoly business to compete with other businesses in providing services such as DE in a competitive market. Some might therefore argue that network businesses should be confined to providing and managing network infrastructure, and that they should not be permitted to provide and manage alternatives such as DE. However, this approach conflates the two roles of the network business: on the one hand as network planner and on the other as network owner/manager.

It is quite legitimate for the regulator to ensure that network businesses do not use their monopoly position *as network owners and managers* to cross-subsidise or otherwise unfairly compete with other providers of DE. However, the regulator should ensure that *as the network planner, the network business* delivers the least cost options for providing services, whether this is via network infrastructure or by demand management. If the network business is able to earn a profit on network infrastructure investment but not to an equivalent degree from DE, then this not only creates an inefficient regulatory system, but also unfairly disadvantages the entire DE industry relative to providers of network infrastructure.

What is potentially even worse is that this approach to exclude network business from supporting demand management can lock network businesses into a declining industry paradigm, and it can stymie the development of new DE services and offerings for consumers, perpetuating a more expensive lower quality and less innovative electricity sector.

The key question for the regulator, therefore, is not so much how to constrain the network business's potential abuse of its *monopoly* power as a supplier of DE services, but rather how to ensure that the network business's *monopsony* power as the sole purchaser of network services does not exclude the potential for DE providers to find a market.

These themes are discussed further in the report, *Restoring power: cutting bills and carbon emissions with demand management* (Dunstan et al. 2013) which proposes regulatory reform to ensure a more level playing field for energy efficiency demand management and other DE options.

4.8 Conclusion

Electricity utilities and network businesses should be supported to procure and facilitate a least cost mix of energy efficiency, demand management and generation and storage solutions. However, to do this requires accessible, reliable, detailed information about where these resources should be deployed. Network Opportunity Maps, as they are currently being developed in Australia, can be a powerful innovative tool to develop this DE market.

Network Opportunity Maps can deliver the following outcomes:

- nationally consistent, annually updated, publicly accessible online maps of network constraints and potentially avoidable investment in electricity transmission and distribution networks

- the facilitation of more rapid and efficient development of energy efficiency, demand management and renewable and other decentralised energy resources
- a contribution to lowering electricity costs, raising energy productivity, lifting network capital efficiency and developing markets for decentralised energy.

However, the success of Network Opportunity Maps in delivering these outcomes will depend crucially on two key factors:

- how enthusiastic network businesses are to embrace the opportunities created by the rise of decentralised energy
- how willing the network business regulator, the Australian Energy Regulator, is to ensure that network businesses are incentivised to support decentralised energy on equal terms with traditional network infrastructure investment.

Section 8.5 discusses policy reform to facilitate such outcomes. In particular, section 8.5.4 discusses some very encouraging progress with the recent announcement about the revised Demand Management Incentive Scheme in the NEM (AER, 2017c). Section 8.5.4 also suggests a series of concrete policy proposals to support least cost outcomes in relation to network resource procurement (see Recommendations N18 to N22).

Chapter 5. Institutional Barriers to Decentralised Energy

5.1 Introduction

As noted in Chapter 2, there is abundant evidence that increased adoption of decentralised energy has the potential to save consumers billions of dollars per annum in Australia. The evidence suggests that effective electricity DM could support this outcome, while at the same time enhancing the economic performance of both electricity suppliers and the wider economy and also significantly reducing carbon emissions. Electricity DM offers a win-win-win outcome for consumers, suppliers and the environment. The evidence has been available for several decades, yet there has been very little progress in applying DM in Australia over this time.

This raises the crucial question, 'What obstructs the adoption of electricity DE and DM in Australia?' This chapter examines this question in detail. It first reviews the literature on this question before offering a conceptual analysis of barriers. It employs a novel classification of institutional barriers and then presents and interprets data from a survey of stakeholders' views on the relative importance of a range of institutional barriers to the application of DM in Australia.

By providing a coherent explanation of the institutional barriers to the implementation of cost-effective DM, it is intended that this analysis will facilitate a greater willingness on the part of policy makers, regulators and electricity utilities to take steps to overcome these barriers and realise the benefits of DM.

5.1.1 Technical vs. institutional barriers

There are numerous ways to analyse and classify barriers to DM. This thesis makes a distinction between technical and institutional barriers. ***Technical barriers*** relate to the characteristics of the DM itself – what it is and what it costs – its technological and economic characteristics. ***Institutional barriers*** are barriers that affect how people relate to DM opportunities, through the institutions of society- its laws and regulations, its conventions and markets, its organisations, its values and its culture.

To illustrate, consider the following example from the United States described by Koomey et al. (cited in Brown, 2001, p. 1198):

> Efficient magnetic ballasts for fluorescent lighting were commercially available as early as 1976. They were a well-tested technology, with performance characteristics equal to or better than standard ballasts by the early 1980s. By 1987, five states – including California and New York – had prohibited the sale of standard ballasts. But the remaining three-quarters of the population chose standard ballasts over efficient ballasts by a ratio of 10-to-1, even though the efficient magnetic ballast paid back its investment in less than two years for virtually all commercial buildings (Koomey et al., 1996). The time required to establish retail distribution service networks and to gain consumer confidence are typical causes of slow innovation diffusions such as this. (Since 1990, federal standards have prohibited the sale of the standard ballast).

In this example, the decentralised energy technology was technically proven and economically attractive, but was generally not being adopted. It is possible that over time, the 'free operation' of the market may eventually have led to greater uptake of efficient magnetic ballasts and the elimination of the less efficient option. However, in this case, the understanding of the institutional barriers led to the US federal government banning standard ballasts. This delivered an outcome that was both economically and environmentally superior.

Figure 5-1 below provides a conceptual framework for describing the relationship between technical and institutional barriers. As illustrated, the range of technologically feasible scenarios, with varying economic and social/environmental outcomes, is limited by technical barriers – the 'technology frontier'. According to this conceptual framework, best practice is achieved at some point on the technology frontier. At this frontier, there is a trade-off between higher economic outcomes and higher environmental and/or social outcomes. So better economic outcomes can only be achieved by forgoing environmental and social outcomes and vice versa. In this case, collective and individual judgements must be made regarding the balance between economic outcomes on the one hand and environmental and social outcomes on the other. It is around these 'trade-off' issues that much of the debate about economic and sustainability issues is conducted.

However, to the extent that institutional barriers obstruct efficient outcomes, current practice falls short of the technology frontier and therefore falls short of best practice. By reducing or removing these institutional barriers that currently obstruct us from attaining best practice, no trade-off is required between economic and environmental/social outcomes. It is possible to improve economic, environmental and social outcomes simultaneously. Shifting from an atavistic, competitive perspective around trade-offs towards a collaborative one that aims to overcome institutional barriers can be crucial to collaboratively tapping the available opportunities for mutual benefit.

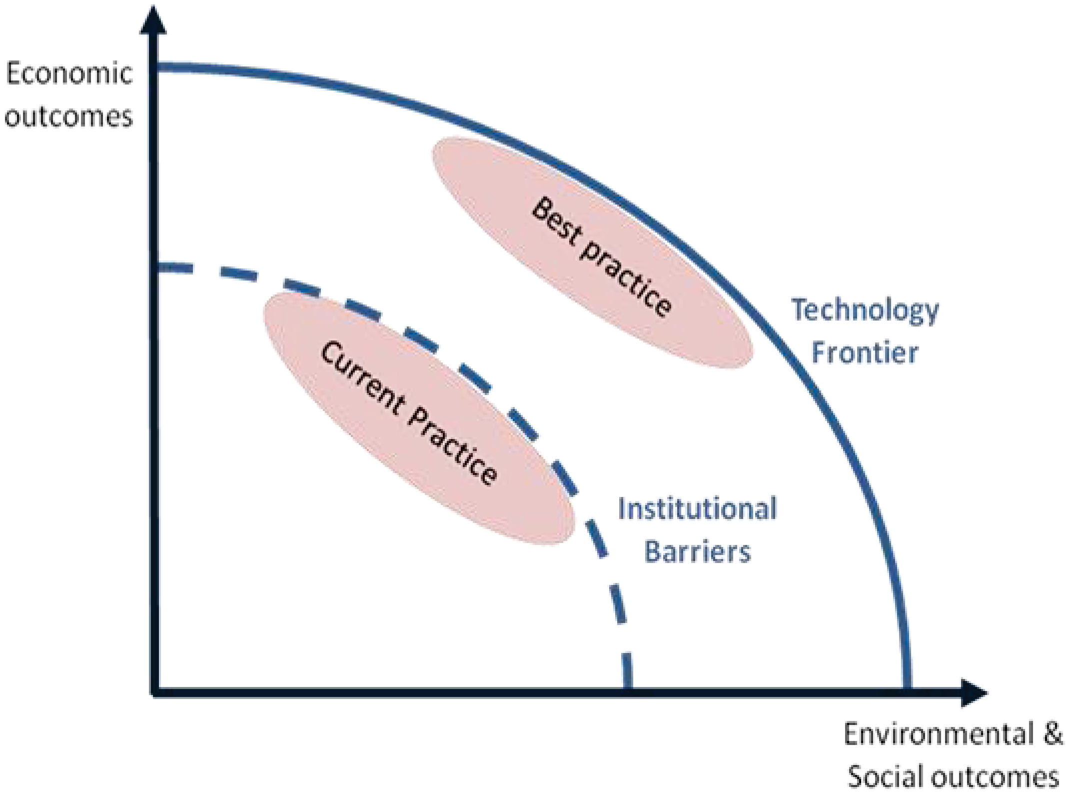


Figure 5-1 Conceptual framework for institutional barriers to decentralised energy

While the collective benefits of addressing institutional barriers are often overlooked and are the focus of this research, this is not to discount the major potential benefits available from addressing technical barriers. Pushing out the technology frontier, through technological innovation and economies of scale has been a major factor in raising living standards and improving social and environmental outcomes.

Technical barriers are important and there are major potential benefits to be realised through developing policy tools to overcome these barriers. Policy tools to support technical innovation, research and development are therefore crucial complements to policy tools to address institutional barriers. However, the particular focus of this thesis is on institutional barriers and policy tools rather than on technical barriers (Cantner and Pyka, 2001).

5.2 Institutional barriers as market failure

In Australia, as in many Western market economy countries, the merits of policy are often assessed from the point of view of economic benefit cost analysis, and in particular, what is often described as a 'neoliberal' or 'market fundamentalist' philosophical position that argues against policy 'intervention' in the free operation of markets unless and until clear evidence of market failure has been presented. While in principle this may seem a reasonable approach to ensure economically efficient policy, in practice, at least in relation to electricity DM in Australia, this approach has often reflected a bias against effective policies which could deliver more economically efficient outcomes via DM.

The following example illustrates this paradigmatic bias at work in relation to DM policy making in Australia. When the Industry Commission (the predecessor to the current Productivity Commission) undertook an inquiry into the *Costs and benefits of reducing greenhouse gas emissions* in 1991, the Commissioner Mick Common had this to say in response to a suggestion that there is extensive cost-effective energy conservation potential lying idle: 'Economists often express considerable incredulity on this and the way some of them put it is it is equivalent to saying that there are lots of $10 bills lying about in the streets and nobody is picking them up' (Industry Commission 1991a, p.146).

So while advocates of DM might lament the prevailing institutional bias, the pervasiveness of this neoliberal paradigm in policy making means that describing institutional barriers from within this dominant paradigm is likely to be crucial to making the case for reform. In the current Australian policy environment, identifying a significant market failure is often seen as an essential condition for receiving a 'licence' to intervene in the market. While the neoliberal paradigm involves a range of debatable political, social and economic assumptions, the key approach in this thesis involves addressing market failure *consistent with* the neoliberal paradigm. To this end, this thesis adopts the conventional approach of prefacing the case for policy reform with a detailed examination of market failure.

'Market failure' refers to the operation of real world markets departing from the theoretical ideals of perfect competition within neoclassical economics. See for example, the Productivity Commission's discussion of market failure in *The Private Cost Effectiveness of Improving Energy Efficiency* (2005, p. xxviii).

The Australian Government's *Best Practice Regulation Handbook* (Australian Government 2007, p. 61) defines market failure as 'situations in which markets fail to allocate resources efficiently'. Market failure can occur under 'conditions of a market that violate one or more of the neoclassical economic assumptions that define an ideal market for products and services such as rational behaviour, costless transactions, and perfect information' (Brown, 2001, p. 1199) .

Jaffe and Stavins (1994) group market failures into the following categories:

1) misplaced incentives;

2) distortionary fiscal and regulatory policies;

3) unpriced costs or externalities;

4) unpriced public goods or benefits; and

5) insufficient and incorrect information.

Fisher and Rothkopf (1989, p. 405) offer an alternative classification of market failures in the allocation of resources in the energy sector:

1) National security – inadequate incentive to individual importer to restrict oil imports;
2) Environmental quality – no incentive to protect environment;
3) Increasing returns – natural monopoly;
4) New technology – spillovers from research, downstream market failures;
5) Residential conservation – inability of low-income consumers to finance;
6) Landlord/tenant – inadequate incentives for either party to conserve;
7) Non-renewable resources – private market discount rate too high; and
8) Transaction costs – inadequate or hard-to-use information on energy efficiency.

It is worth noting that, unlike Fisher and Rothkopf's approach, in my analysis of barriers below, I do not regard high transaction costs as either an institutional or a technical barrier. This is because higher transaction costs are a *consequence* or a *symptom* of barriers rather than barriers in their own right. Indeed, all of the institutional barriers discussed below can be considered in terms of how they increase transaction costs for DE. For example, as Sanstad and Howarth (1994, p. 815) point out:

> Problems of imperfect and asymmetric information may be viewed from the perspective of transaction cost analysis: the economic gains available from

> increased energy efficiency may be outweighed by costs in gathering, assessing and applying information on the characteristics and performance of energy using equipment, installing such measures as thermal shell improvements, making decisions about energy efficiency and energy utilization, or reaching and enforcing agreements among interested parties.

Sanstad and Howarth (1994, p. 812) argue that 'the equation of normal and efficient markets is a fallacy that can only serve to distort energy policy analysis'. They argue that 'in light of contemporary theory, the intuitions expressed by the market barriers concept may in fact be closer to the theoretical mainstream than the views of the skeptics' (Sanstad and Howarth, 1994, p. 812).

On this basis, Sanstad and Howarth (1994, pp. 814-816) discuss key market imperfections such as (1) the existing regulatory environment, (2) imperfect information, (3) asymmetric information, (4) transaction costs, (5) imperfections in capital markets and (6) bounded rationality in energy decisions.

These barriers can be presented in a standard microeconomic supply and demand analysis, as illustrated in Figure 5-2. The efficient level of consumption of a given commodity, such as decentralised energy resources is q_0, at price p_0, reflecting the underlying efficient cost of supply and the underlying ('efficient') level of demand. However, due to the transaction costs (including uncertainty, risk and inconvenience) associated with institutional barriers, the effective demand falls from $Demand_0$ to $Demand_1$ while the cost of supply rises from $Supply_0$ to $Supply_1$. As a consequence, the quantity of DE supplied and consumed falls from q_0 to q_1. (Note, however that the final price of DE, p_1, may be higher, lower or unchanged relative to the original price, depending on the shape and slope of the supply and demand curves.)

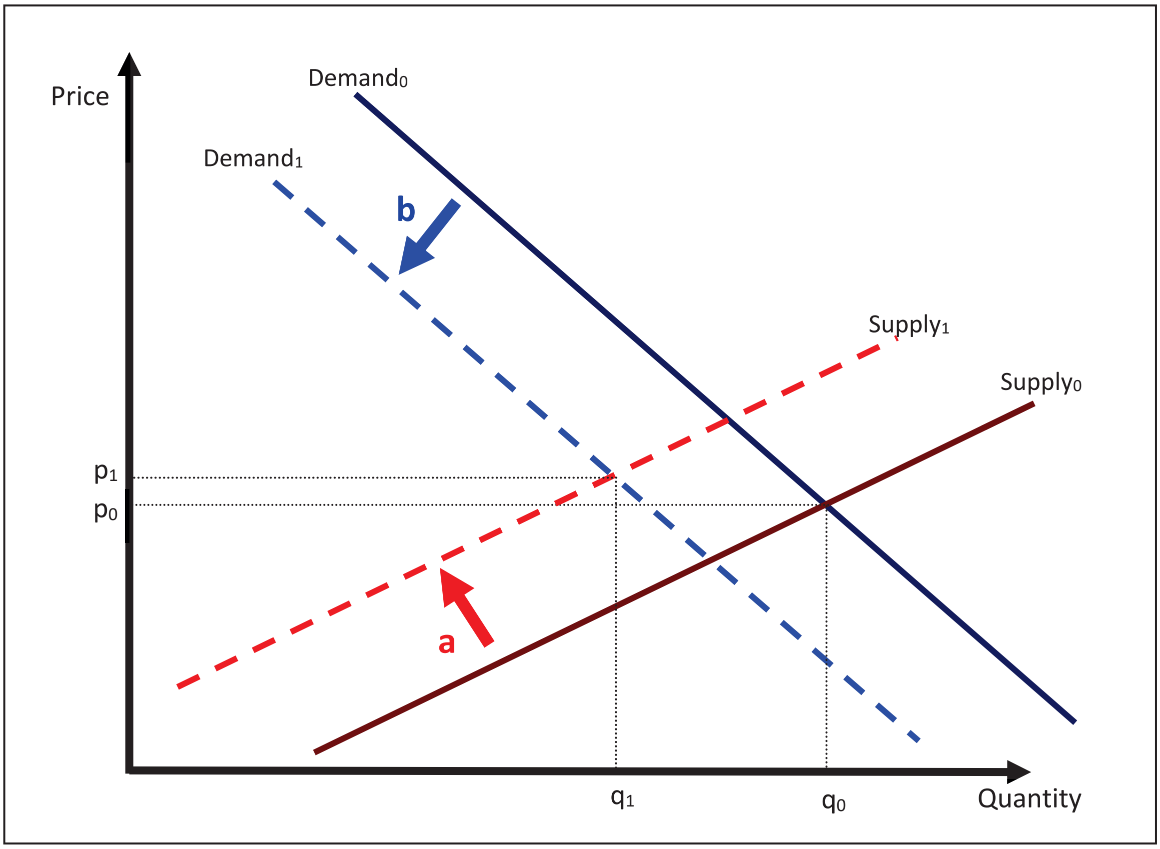


Figure 5-2 Institutional barriers and market for decentralised energy (demand and supply)

Where institutional barriers do not entirely block decentralised energy, the effect is to create additional costs and efficiency losses in overcoming the barriers. These additional 'transaction costs' ultimately have to be borne by the purchaser of the decentralised energy technology. This means that the effective demand for decentralised energy falls short of the total potential demand or underlying demand and so the total adoption of decentralised energy is reduced. This effect is illustrated in Figure 5-3.

It may be argued that for many DE technologies with large economies of scale (such as rooftop solar PV systems), a downward sloping supply curve would be more appropriate. While this may in many cases be true, this would not significantly change this analysis.

I return to this analysis in considering policy tools to overcome institutional barriers in Section 6.3.

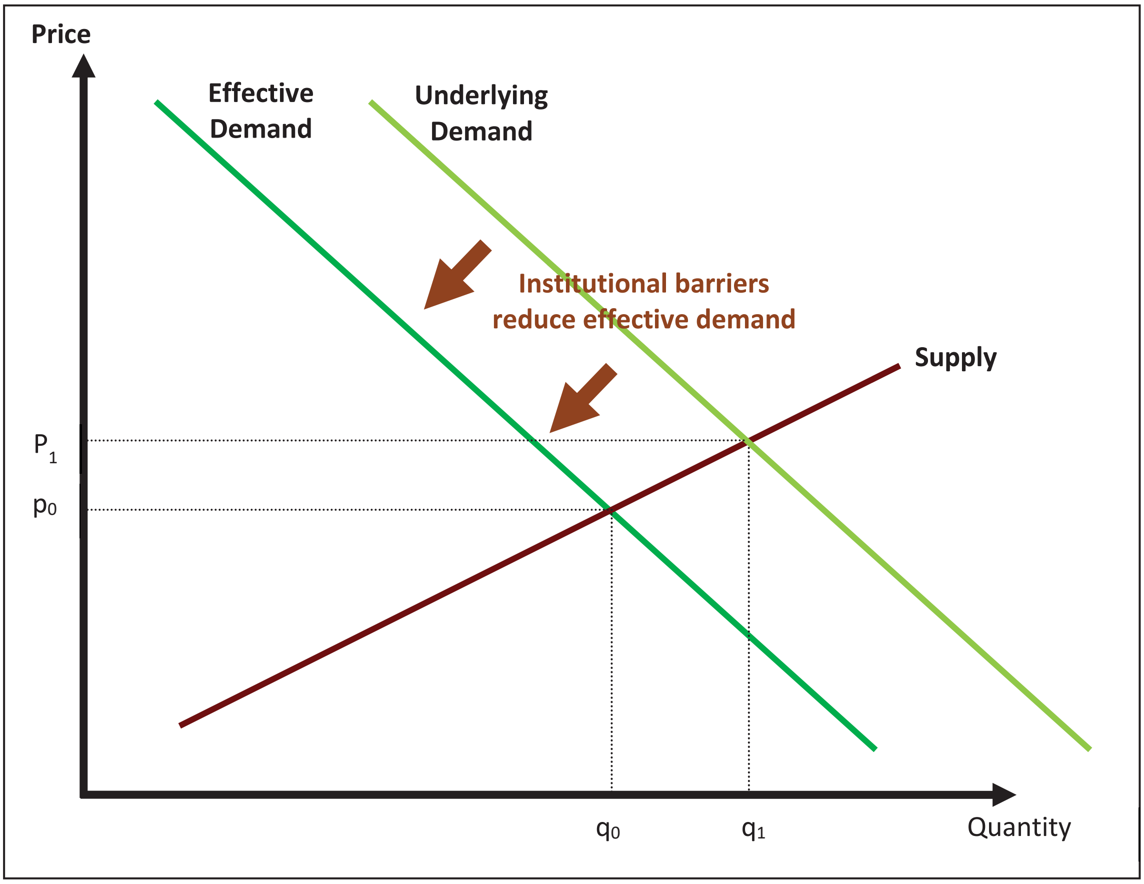


Figure 5-3 Effect of institutional barriers on the demand for decentralised energy

Simply demonstrating a significant market failure is seldom sufficient to bring about government policy change or regulatory intervention. It generally must also be clearly demonstrated that the policy intervention itself would deliver a better outcome for the community and economy, and that the cost of the intervention is unlikely to exceed the benefits derived (Australian Government, 2007).

However, as Kingdon (1995) has observed, even these conditions will often be insufficient to bring about change. Kingdon suggests an advantageous and viable ***policy*** option is just one of three key ingredients of an effective 'window of opportunity' for public policy change. The other two ingredients are: a clearly perceived ***problem*** and conducive ***political*** environment.

5.3 Towards a theory of institutional barriers

Institutional barriers to decentralised energy and demand management, and the potential benefits of addressing these barriers, have been discussed for decades in countless government reports, inquiries and independent studies, and in academic literature. This section provides a brief overview of this literature.

Shortly after the first oil price shocks of the early 1970s, Amory Lovins articulated an alternative vision for energy policy in his influential paper *Energy strategy: the road not taken* (Lovins, 1976). Lovins introduced the concept of energy efficiency: ‘using less energy to produce more economic output’ (Golove and Eto, 1996, p. 6). Soon after the publication of Lovins’ paper, the ideas he presented on energy efficiency began to have a significant impact on energy policy. The concept Lovins introduced, ‘coupled with the review of the apparently highly inefficient use of energy by society at the time, led to a conclusion that the market alone was not working to provide the most desirable social outcome’ (Golove and Eto, 1996, p.6).

The ideas that followed about energy efficiency ‘were often expressed as questions about the existence and magnitude of an efficiency gap’. The term ‘efficiency gap’ refers to ‘the difference between levels of investment in energy efficiency that appears to be cost effective based on engineering-economic analysis and the (lower) levels actually occurring’ (Golove & Eto, 1996, p. 6). The significant gap between current and optimum levels of energy efficiency was thought to exist because ‘for a variety of reasons, households, businesses, manufacturers, and government agencies all fail to take full advantage of cost-effective, energy-conserving opportunities’ (Hirst and Brown, 1990, p. 267). In addition, following on from the energy crisis, ‘some analysts insisted that efforts should also be made to moderate the demand for energy by adoption of conservation measures’ (Blumstein et al., 1980, p. 355).

Blumstein et al. presented the first analysis of this apparent divergence or ‘gap’ and proposed that ‘although economically rational responses to the energy crisis, energy conservation actions may be hindered by social and institutional barriers’ and that ‘a “hands-off” strategy may not be sufficient’ (Blumstein et al., 1980, p. 355).

Analysts began to present a case for closing the energy efficiency gap, pointing out many economic and societal gains to be had such as cost savings, improved industrial competitiveness and environmental benefits (Hirst and Brown, 1990). Analysts shifted their attention to analysis of the possible obstacles inhibiting energy efficiency and increasingly paid attention to identifying and classifying the ‘institutional barriers’ to energy efficiency and energy conservation. Despite all of the discussion that has taken place since, the barriers first identified by Blumstein et al. (1980) almost forty years ago remain just as relevant today.

5.4 Review of selected barrier classification models

There is a wide diversity of approaches and a lack of consistent structure in classifications of institutional barriers in the academic literature. Blumstein et al. (1980) were the first to assert that barriers hindering the market from achieving a satisfactory outcome were embedded in social norms and institutional arrangements. Blumstein et al. (1980, p.356) offered a taxonomy of regularly occurring barriers:

1) misplaced incentives,
2) lack of access to financing,
3) flaws in market structure,
4) mis-pricing imposed by regulation,
5) decision influenced by custom, and
6) lack of information or misinformation.

Subsequently, a seventh barrier, referred to as ‘gold plating’ was added to the taxonomy (Golove and Eto, 1996).

Some have classified barriers as either structural or behavioural. For example, Hirst and Brown (1990, p. 267) explain structural barriers as including ‘distortions in fuel prices, uncertainty about future fuel prices, limited access to capital, government fiscal and regulatory policies, codes and standards, and supply infrastructure limitations’. They consider behavioural barriers to be ‘attitudes toward energy efficiency, perceived risk of energy-efficiency investments, information gaps, and misplaced incentives’ (Hirst and Brown, 1990, p. 267). Hirst and Brown (1990, p. 269) make a distinction between the two types of barriers:

> Structural barriers result from the actions of many public and private sector organisations and are primarily beyond the control of the individual end-user. Behavioral barriers, on the other hand, are problems that characterise the end-user’s decision-making, although they may also reflect structural constraints.

Other types of barrier classifications also appear in the literature. For example, in addition to the six classes of barriers presented above, Blumstein et al. (1980) discuss how barriers can be classified as stable or transient. Transient barriers, because they are caused by inertia, ‘may be tenacious, but when broken down, they stay down’ and ‘for the most part, one expects that transient barriers will eventually be overcome by the normal workings of the market’

(Blumstein, Krieg et al., 1980, p. 358). On the other hand, stable barriers are 'more deeply embedded in the social and institutional fabric' and 'when broken down, they tend to reappear in altered form' (Blumstein et al., 1980, p. 358).

Another typology is presented by Reddy (1991) in which barriers are classified by actor, from the energy consumer to global financial agencies. Under Reddy's (1991) typology, for the case of energy consumers, there are the ignorant, the poor and/or first-cost sensitive, the indifferent, the helpless, the uncertain and the inheritors of inefficiency. For the end-use equipment manufacturers, there are the efficiency-blind and for the end-use equipment providers, there are the operating-costs blind (Reddy, 1991). On the side of the energy producers and distributors, there are the supply obsessed, the centralisation-biased and the supply monopolists. In the case of the local and national financial institutions, there are the supply biased, the unfair and those with anti-innovation attitudes (Reddy, 1991).

For government/country actors, Reddy's (1991) typology identifies the uninterested government, the skills-short government, the government without adequate training facilities, the government without access to hardware and software, the capital-short government of an infrastructure-poor country, the sales-promoting regulator, the powerless energy-efficiency agency, the cost-blind price fixer, the fragmented decision-maker, the large-is-impressive syndrome and the large-is-lucrative sponsor. Lastly, for the international, multilateral and industrialised country funding and aid agencies, Reddy (1991) presents: the inefficient technology exporter, the supply biased, the anti-innovation attitude, the large-is-convenient funder, the project-mode sponsor and the self-reliance underminer.

DeCanio (1993, p. 906, p. 906) explains that certain barriers faced by firms can mean that 'many investments in energy efficiency fail to be made despite their apparent profitability' because 'internal hurdle rates are often set at levels higher than the cost of capital to the firm'. This situation is due to 'bounded rationality, principal-agent problems, and moral hazards' (DeCanio 1993, p.906). According to DeCanio, if governments were to provide informational and organisational services beyond the traditional regulatory framework, the dual goals of improving overall energy efficiency and increasing private sector productivity could be achieved (DeCanio 1993).

5.4.1 The Stern Report

The landmark report on *The Economics of Climate Change* ('The Stern Review', 2006), made the case for policies which price greenhouse gases and which support low-emission technology development in order to tackle climate change. Stern (2006, p. 427) cautions that 'even if these measures are taken, barriers and market imperfections may still inhibit action, particularly on energy efficiency'.

Stern (2006, p. 427) sees the considerable untapped energy efficiency opportunities in buildings, transport, industry, agriculture and power sectors as evidence of the impact of market failures and barriers which include: 'hidden and transaction costs such as the cost of the time needed to plan new investments; lack of information about available options; capital constraints; misaligned incentives; as well as behavioural and organisational factors affecting economic rationality in decision-making'.

Stern groups the barriers into three main categories: (1) financial and 'hidden' costs and benefits; (2) multiple objectives, conflicting signals, or, information and other market failures; and (3) behavioural and motivational factors (Adapted from the Carbon Trust, The UK Climate Change Programme: Potential Evolution for Business and the Public Sector cited in Stern 2006, p.429).

While an individual or firm would typically balance the financial costs and benefits of any investment in energy-using technologies, Stern (2006) notes that hidden or transaction costs are also required to assess the full range of costs and benefits. A study by Hein and Blok (cited in Stern, 2006, p. 430) found search and information costs of energy efficiency measures of between three and eight per cent of total investment costs.

In addition, a lack of available capital will prevent actors from investing in more energy-efficient processes which usually have a high upfront capital cost, but a lower overall cost when the energy cost savings are taken into account. Likewise, incentive failures restrict the effectiveness of price instruments, for example 'in the buildings sector is the "landlord-tenant" problem in which landlords do not invest in the energy efficiency of their asset, because tenants benefit from lower energy bills, and more efficient capital typically does not command sufficiently higher rents' (Stern, 2006, p. 431).

5.4.2 The Garnaut Review

According to the most comprehensive Australian review on the economics of climate change, the Garnaut Review (2008, p. 443), ‘externalities in the provision of information and principal-agent issues inhibit the use of distributed generation and energy-saving opportunities in appliances, buildings and vehicles’. As Garnaut (2008, p. 444) states:

> Two kinds of market failures are especially important in inhibiting the adoption of low-emissions technologies and practices. One relates to externalities in the supply of information and skills. The other involves a principal-agent problem – where the party that makes a decision is not driven by the same considerations as another party who is affected by it.

McKinsey and Company (cited in Garnaut, 2008, p. 445) ‘suggests that the majority of technically low-cost mitigation opportunities in Australia occur in sectors affected by information and principal-agent market failures’. Market failures, Garnaut argues, are most likely to occur ‘where mitigation opportunities are small relative to the transaction costs of securing them’(Garnaut, 2008, p. 444).

The Garnaut Review (2008, p. 445) presents a market failure framework comprising:

- Public good information market failures (& ‘bounded rationality’);
- Information asymmetry market failures (& ‘adverse selection’);
- Information spillover market failures; and
- Principal-agent market failures.

The following table summarises the market failures highlighted within the Garnaut framework (Garnaut, 2008, pp. 445-454).

Table 5-1 Garnaut's summary of market failures

Public good information market failures	Includes the public good nature of some information and bounded rationality. As some information is a pure public good, one person's use of that information does not prevent others from using it. 'Where information has public good characteristics it is likely to be underprovided by the private sector'(Jaffe & Stavins 1994 cited in Garnaut, 2008, p. 446) and 'as firms are not able to capture all of the benefits from public good information, there is insufficient incentive to make information as extensive and widely available as consumers may demand'(Garnaut, 2008, p. 447).
Information asymmetry market failures	'Information asymmetry occurs when two parties to a transaction do not have equal access to relevant information' (Garnaut, 2008, p. 452). For example, 'There are potentially significant information asymmetries where appliances, vehicles and houses are not energy rated. It would be extremely difficult for non-experts to determine the ongoing energy use of an appliance, for example, without outside assistance. This allows opportunism, as a product manufacturer could mislead a buyer before they buy it. However, this can be costly and individuals may choose not to invest in further information gathering, avoid the transaction or place a risk premium on the transaction' (Garnaut, 2008, p. 452). 'Information asymmetry can lead to adverse selection, which can occur where sellers are better informed than buyers, resulting in lower-quality goods dominating a market' (Akerlof 1970 cited in Garnaut, 2008, p. 453).
Information spillover market failures	'Some actions by parties can result in benefits to other parties, without those other parties paying for them. Early adopters of some low-emissions options bear additional costs in gathering information, developing skills for adopting the option and testing the reliability of the option (Jeffee et al. 2004). In some cases, the boundary between early adoption and innovation can be blurred. However, early adopters are often unable to capture the knowledge and skill spillover benefits that accrue to other firms, other industries, and the community more broadly. This acts as a disincentive to early adoption of novel technologies and practices'(Garnaut, 2008, p. 454).
Principal-agent market failures	Occurs when one person (the principal) pays an agent for a service, but the parties face differing incentives and the principal cannot ensure that the agent will act in the principal's best interest. 'Principal-agent problems may entirely insulate some decisions from a carbon price, potentially reducing the adoption of low-emissions options. For example, as residential tenants pay energy bills, landlords may not install energy-efficient appliances' (IEA 2007 cited in Garnaut, 2008, p. 454).

5.4.3 International Energy Agency

The International Energy Agency's (2005, p. 23) Information Paper on energy efficiency policy and programs in IEA countries provides the following summary of barriers to cost-effective energy efficiency :

> Energy efficiency proponents point to a wide range of market failures or barriers in order to justify energy efficiency policies and programmes. These market barriers and failures include:
>
> - the limited supply and availability of relatively new energy efficiency measures in the marketplace;
> - consumers lacking or having incomplete information about energy efficiency options;
> - some consumers lacking the capital to invest in energy efficiency measures;
> - fiscal or regulator policies that discourage energy efficiency;
> - misplaced incentives whereby the party designing, constructing or purchasing a building or price of equipment, or the landlord in rental property, generally seeks to minimize first cost rather than lifecycle cost;
> - consumers or businesses paying little attention to energy use and energy savings opportunities if energy costs are a small fraction or the total cost of owning or operating a home, business or factory; and
> - energy prices that do not reflect the full costs imposed on society by energy production and consumption.

The IEA's view of barriers was also summarised in 2003, as illustrated in the following table.

Barrier grouping	Barrier[a]	Key problem associated with barrier	Necessary conditions
Information and behavioural barriers	Price distortion	Costs associated with energy and incumbent technologies may not be included in their prices; energy and incumbent technologies may be subsidised	
	Information	Information on availability and nature of an energy efficient product is not easily available or accessible at time of investment.	Clearer price signals
	Buyer's risk	Perception of risk may differ from actual risk (e.g. perceived 'pay-back gap')	Improved information provision
	Transactions costs	Perceived costs involved in making a decision to purchase and use equipment outweigh perceived benefits (overlaps with "market organisation" below)	Reduce transaction costs
	Bounded rationality	Constraints on time, attention, and the ability to process information lead consumers to rely on imprecise routines and rules of thumb. A consequence of this type of decision-making is that actors may not maximise utility, even when given good information and appropriate incentives	
Market organisation barriers	Finance	The initial cost of a project may be higher than the finance threshold; Poor or constrained access to funds	
	Inefficient market organisation	Principal agent problems (International Energy Agency, 2007f); established companies may have market power to guard their positions	Enhanced access to finance
	Insufficient/excessive/ inefficient regulation at national or international level	Regulations and codes not keeping pace with development	Improved public and private decision-making frameworks
Technological barriers	Capital stock turnover rates	Sunk costs, tax rules that require long depreciation Inertia in the energy system	Proactive energy management
	Uncompetitive market price	Scale economies and learning benefits have not yet been realised	Improved capital stock
	Technology-specific barriers	Relating to existing infrastructure in regard to hardware and the institutional skill to handle it	Enhance skills

Figure 5-4 A typology of market barriers and necessary conditions

(Jollands et al., 2010)

5.5 Critiques of barrier classifications

It should be noted that some critics have taken issue with the very concept of barrier classification models. For example, Weber (1997, p. 834) argues against barrier classifications on the following grounds:

> First, barrier models assume that improved efficiency is the result of a particular action (e.g. buying more efficient equipment, retrofitting building shell or decree of an energy tax). Energy conservation which results from the omission of an action (e.g. not buying a certain machine) or doing something in a different way (e.g. integrated instead of isolated planning), cannot be described by a barrier model. Barrier models are limited insofar as they can only describe energy conservation in the sense of positive actions. Thus, they do not represent the whole range of energy conservation options.
>
> Second, barrier models do not question the purpose of an action. They focus on means to given ends. Preferences are exogenous and need not to be legitimised. Action is modelled technically in the sense that the challenge lies within the minimisation of means (i.e. energy consumption). The barrier model approach ignores the level of consumption and favours technical solutions.
>
> Third, barrier models are based on the assumption that there is an ideal level of efficiency. The existence of barriers as well as the level of inefficiency is derived by technical options (e.g. state of the art). Barrier models ignore social techniques and the social conditions of technology development.

An alternative critique of barriers analysis by Weber (1997, p. 834) is that market barrier classifications are not typologies as such and ‘in fact each real barrier has its institutional, economic and organisational and behavioural aspects’. According to Weber, as barriers are invisible and not observable, they cannot be empirically classified, and thus barrier classifications are ‘derived from theory and propelled by different concepts of action in order to remove obstacles, that is, theories of institutions, economic theories, organisational theories and theories of human behaviour’.

Weber (1997, p. 834) adds, however, that ‘practical measures can be realised for better institutional, organisational, behavioural and market conditions to make energy conservation more successful’.

5.6 Rethinking barrier classifications

The inconsistencies in the classifications of institutional barriers to DE in the literature discussed above have likely contributed to the confusion around barriers and eroded the effectiveness of arguments for addressing them. Notwithstanding the challenges, barrier classification is an important means of better understanding the realistic potential of DE and the means to achieve it. Greater coherence and consensus in barriers analysis is likely to lead to greater coherence and consensus in developing policy responses to redress these barriers.

As noted in Section 5.1, this chapter focuses on institutional, not technical barriers. This is not to discount the importance of technical barriers and the potential benefits of overcoming these. For example, the recent boom in rooftop solar photovoltaics in Australia is likely to have been driven much more by cost reductions associated with technological improvement than by overcoming institutional barriers.

There remain many technical barriers to decentralised energy worthy of further analysis and research. Some examples of technical barriers not covered in this thesis are:

- safety issues surrounding the isolation of distributed generators during periods of grid shutdown
- managing grid stability with the integration of high levels of distributed renewable energy sources
- managing distribution network faults currently associated with distributed generators
- user interfaces with existing smart meters lacking usability and interoperability .

However, as important as resolving technical barriers is, they are outside the scope of this research and thesis.

As noted above, and illustrated in Figure 5-5 below, barriers to DE can be broadly divided into technical barriers that relate to the nature of the technology and its cost, and institutional barriers that relate to how consumers, organisations and governments engage with the technology. In the case of decentralised energy, there are many instances where technologies that are technically and economically viable are not applied because they face institutional barriers.

Barriers							
Technical		Institutional					
Current Technology	Current Costs	Regulatory Failure	Inefficient Pricing	Payback Gap	Split Incentives	Lack of Information	Cultural Barriers

Figure 5-5 Technical and institutional barriers

(Dunstan et al. 2011a)

As with any good classification system, the objective in classifying institutional barriers is not to devise 'the correct system', but rather to develop a useful system given the context. To paraphrase the principle of as Occam's Razor, such a classification system should be as simple as possible, but no simpler. Ideally, the classification should include categories that are 'mutually exclusive and collectively exhaustive'. In other words, each barrier should fit into one category, but no others. Based on these criteria, and drawing on the review of existing barrier frameworks discussed in Section 5.4, the following simplified classification of seven types of institutional barriers to decentralised energy is proposed:

1. **Imperfect information** – lack of access to relevant information
2. **Split incentives** – the challenge of capturing benefits spread across numerous stakeholders
3. **Payback gap** – differences between stakeholders regarding what is considered an acceptable time period for recovering investments, in this case differences between energy consumers and decentralised energy proponents on the one hand, and large centralised energy supply utilities on the other
4. **Inefficient pricing** – the failure to reflect actual costs (including environmental costs) accurately in energy prices
5. **Regulatory barriers** – the biasing of regulation against decentralised energy resources
6. **Cultural barriers** – resistance to, and scepticism about, the use of decentralised energy on the part of individuals and organisations (including utilities, regulators and policy makers)
7. **The interaction of barriers** – resulting in confusion on the part of stakeholders in relation to the availability, practicality or competitiveness of decentralised energy.

These seven barrier categories are summarised in the "Barriers Spectrum" in Figure 5-6.

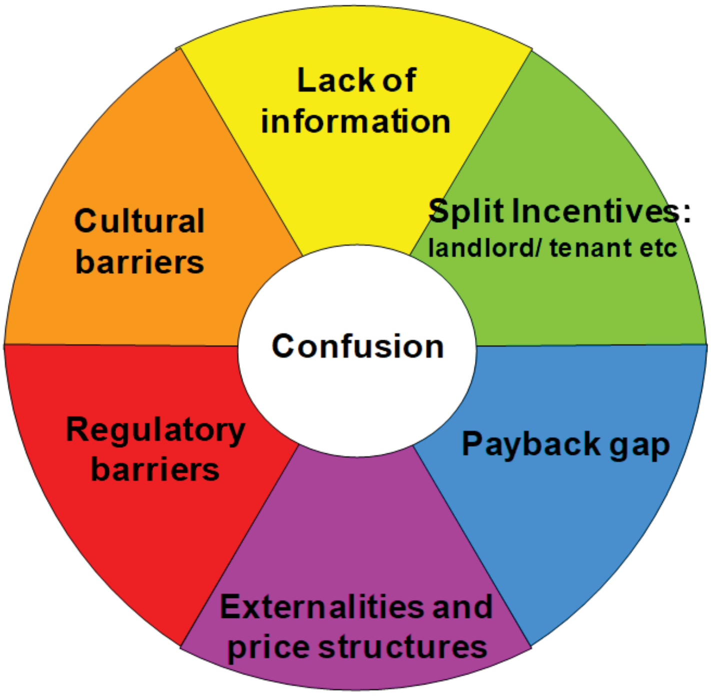


Figure 5-6 The Barriers Spectrum: Institutional barriers to decentralised energy (Dunstan et al. 2011a)

Each of these seven categories of institutional barrier is discussed below. The colour for each subsection heading refers to the colour of the corresponding section of the Barriers Spectrum.

5.6.1 Imperfect information

In orthodox economic theory, full and free information is one of the fundamental precepts of perfect competition on which the efficient operation of the market depends. 'Perfect information' essentially means that consumers and firms have free and immediate access to all relevant information in making decisions about how to produce and procure goods and services. While economists understand that this is never strictly true, it is often used as a simplifying assumption. As the Garnaut Report (2008, p. 446) noted:

> Individuals can never have perfect information relevant to a decision they are making. However, development of an efficient market in goods and services requires individuals to know:
>
> - the options available
> - the rough costs and benefits of the different options
> - how to deploy the options (including hiring experts)
> - the cost of investigating the options.

Unfortunately, in the case of decentralised energy, the simplifying assumption that full and free information is available can disguise major inefficiencies in the operation of markets. As Brown notes, 'the time and cost of collecting information is part of the transaction costs faced by consumers' and therefore, 'where the consumer is not knowledgeable about the energy features of products and their economics (for any of a large number of reasons, including technical difficulties and high costs of obtaining information), investments in energy efficiency are unlikely' (Brown, 2001, p. 1201).

This is the key rationale in Australia for the mandatory energy performance labelling of many appliances and the rating of buildings. As Garnaut notes,

> Governments should not be expected to fill the gap in every situation where individuals lack sufficient information to make good decisions. Producing, finding, and processing information has economic costs that need to be considered in decision making. However, where information barriers are caused by market failures, governments may be able to improve the efficiency of the market (Garnaut, 2008, p. 446).

The following examples illustrate the ways in which limiting access to timely, relevant information can present a significant barrier to the adoption of DE.

Energy operating costs (when purchasing): 'First cost disease'

Many decentralised energy measures involve higher initial purchase or capital costs, but lower ongoing operating costs. For example, this is true of solar and wind power, solar water heating, cogeneration and many energy efficiency options. If reliable information on operating costs is not easily and cheaply available at the time of purchase, this creates a bias in favour of choosing the lowest upfront cost option. This phenomenon is sometimes called 'the first cost disease'.

Energy operating costs (when operating): 'Who pays the bill?'

Even when energy-using equipment is purchased and installed, useful information about operating costs may still be unavailable. Many consumers either do not personally receive consumption and billing information at all (for example, it may be directed to the accounts payable section of a company) or only receive an aggregated bill once every several months. It is difficult to respond appropriately to cost signals if no signals are received.

Benchmarks for energy performance: 'What's normal?'

Even where energy use data is available, it may be difficult to interpret. If credible performance benchmarks are not available, identifying what is good and what is poor energy performance may be difficult. For example, a factory may continue to use an expensive, inefficient and polluting coal-fired boiler simply because it works adequately and its operators are not aware of the availability of better options.

Lack of DE precedents: 'Will it work?'

Even where credible information about relative energy performance is available, reliable information about DE alternatives may be difficult or costly to access. Consequently, while the costs of deploying advanced metering infrastructure may be estimated with reasonable accuracy, the benefits that flow from such an investment can be much harder to anticipate with confidence. It may also be difficult to apprise all stakeholders of the expected benefits about DE alternatives. For example, if the end users are unfamiliar with the technology and unclear about its performance, public resistance to these technologies and policies can emerge.

DE technologies and opportunities: 'What does DE really cost?'

Even where technical information is available and the performance of DE has been demonstrated, reliable information about its fixed and operating costs may be unavailable, particularly in relation to more innovative technologies.

Network planning information: 'DM: when, where, how much?'

One of the key potential benefits of DE, compared to centralised generation, is the ability to locate it close to centres of energy demand and thereby avoid or defer the need for network capacity. Smith (2007, p. 6) has noted that the opportunities for demand management within a network context are constrained by three factors – location, timing and the amount of peak reduction, as follows:

1. **Location** - opportunities arise only in those specific parts of the network system that are facing constraints and require augmentation;

2. **Timing** - demand management is only required for short periods of system peaks and has its highest value in the period immediately before planned system augmentation investments are to be made; and

3. **Amount** - a specific quantum of peak load reduction is required to replace the need for a system augmentation in time to defer construction of supply side assets. Too little will not allow a deferral and any surplus has no value once a deferral can be achieved.

However, it is difficult for DE options to take advantage of these potential benefits, unless reliable, timely information about such emerging network constraints is easily accessible. As Szatow (2008, p. 4) notes, 'planning information can help level the playing field for alternative energy supply options by providing accurate forecasts of network constraints and opportunities for investment'.

One example of the need for network planning information is in the implementation of Australia's Reliability and Emergency Reserve Trader (RERT). RERT is an avenue for the Australian Energy Market Operator to reserve contracts for when there is 'compelling evidence of market failure' to provide the required level of capacity (AEMC 2009a). The RERT offers the opportunity for demand response to provide reliability when it has the most value to the market, which is at the time of potential shortage of supply and highest prices. However, the lack of quality information available to AEMO about demand-side capability hinders its ability to assess whether DM should be exercised for RERT or not. Improved information about demand-side capability would enhance AEMO's probabilistic assessments of demand-side participation at times of peak demand and subsequently increase their ability to forecast reserve shortfalls[30] (AEMC 2009a).

5.6.2 Split incentives

'Split incentives' refers to situations where a course of action with a collectively desirable outcome is obstructed because it is not in the interests of a particular party. In principle, all such split incentives could be resolved by the party that benefits from the action compensating the party that does not benefit. Indeed, such transactions make up a large share of normal economic activity. However, all such transactions have costs associated with them in terms of time, risks and resources, so in practice many split incentive situations are not resolved.

[30] Note that DM has, for the first time in Australia, been used extensively used for RERT in 2017/18.

The greater the number of parties involved in decisions related to DE investment, the greater will be the transaction costs associated with devising and negotiating a mutually acceptable outcome. Similarly, the lower the level of trust and sense of common purpose between the relevant parties, the more difficult and costly it will be to overcome such barriers. Facilitation through negotiation, awareness raising, education, confidence building, and access to reliable independent energy performance information can often assist in addressing these barriers.

Landlord-tenant problem

The textbook example of split incentives is the landlord-tenant problem, which is often cited in relation to energy efficiency investments in rental accommodation. In this case, the landlord is reluctant to invest in energy efficiency because the benefit would accrue to the tenants over time through lower energy bills. Meanwhile, the tenant is reluctant to pay for investment in energy efficiency as they may be uncertain if they will remain a tenant long enough to reap the benefits. This situation could apply as much to insulating a low-income residential flat as it could to installing intelligent lighting controls in a premium office space.

A variant of this principle is the principle-agent problem, as discussed in Table 5-1, in which 'an agent has the authority to act on behalf of a consumer, but does not fully reflect the consumer's best interests' (Brown, 2001, p. 1199). An example of this is where a design consultant is rewarded for minimising initial or capital costs, rather than life cycle costs for a client.

Complex decision-making within groups

Split incentives can be as pervasive within groups or organisations as they are between them. In particular, where organisations do not have established processes for considering and deciding on issues like investment in DE (such as through a designated energy manager or an energy management plan), then the effort and costs associated with formulating, negotiating, deciding on and implementing a proposal relating to DE may seem prohibitive.

Tragedy of the commons

At the highest level of complexity, split incentives can be characterised as the 'tragedy of the commons' where all parties are disadvantaged by the failure of each to act for the common good (Hardin, 1968). This is particularly relevant to decentralised energy in relation to investment in research and development, as described by Brown (2001, p. 1201):

> The risk of innovation leakage and exploitation by competing firms puts pressure on firms to invest for quick returns (Mansfield, 1994). Technology innovation is typically a longer-term investment fraught with risks to the investor. The result is an under-investment in R&D from the standpoint of overall benefits to society. The problem is particularly difficult in the newly restructured electric sector, where R&D funding has decreased dramatically. Companies will not fund the optimal societal level of basic R&D of new technologies, since many of the benefits of such research will flow to their competitors and to other parts of the economy.

5.6.3 The payback gap

Electricity utilities generally have access to finance more easily and at lower cost than most energy consumers do. Given that DE options often have relatively higher initial or capital costs, but lower ongoing or operating costs, it is not surprising that limited access to finance for managing the higher initial costs is often cited as a barrier to DE. However, some care needs to be taken in relation to this issue. Given the massive growth, both in the finance industry and in the provision of personal and corporate debt over the past two decades, it is far from clear that limited access to finance has been a major barrier retarding the development of DE. On the other hand, there appears to be ample evidence of a large neglected reservoir of cost-effective investment opportunities in DE with relatively short payback periods of a few years or less.

As the Stern Report (2006, p. 429) observed:

> Individuals and firms should invest until the expected savings are equal to the opportunity cost of borrowing or saving (assuming risk neutrality). Studies suggest that individuals and firms appear to place a low value on future energy savings. Their decisions expressed in terms of standard methods of appraisal would imply average discount rates of the order of 30% or more. A 30 per cent discount rate implies that consumers and businesses require DE investments to pay back their initial investment within about three years. The so-called “payback gap” refers to this discrepancy between the payback period that consumers and business demand to be met by many DE investments and the payback period that is required of many other investments (including those made by utility companies in energy supply infrastructure).

This raises the question of why many households appear to be willing to invest in superannuation and other assets that offer a return on investment of say, seven per cent per annum, but seem unprepared to invest in efficient lighting that may offer a return on investment of many times this rate. If many households are able to borrow thousands of dollars to spend on home renovations, large screen televisions or cars, is access to finance really a barrier to DE? There is clearly more at play here than simply access to finance. If part of the answer is that a television or a car is more desirable and cost-effective than DE, then this should also give pause for thought about the limitations of relying on cost minimisation to explain human economic behaviour.

The answer to the above question is likely to lie in part with the other institutional barriers described in this chapter. However, there is another side to the question of financing and the notion of the 'payback gap'. Much debate and analysis around this theme has focused on why energy consumers often seem to require their DE investments to pay for themselves through operating cost savings within two or three years. Similarly, network service providers also tend to require a much quicker return on investment for DE investments than for network augmentation investments. However, of equal significance to the DE payback gap is why the short payback periods do not apply to centralised energy resources. In other words, why do regulated monopolies have ready access to finance with longer payback periods relative to those available to DE providers or energy consumers? This disparity reflects the historical development of the electricity industry, and is a key barrier to the development of DE resources.

5.6.4 Inefficient pricing

There are two dimensions to inefficient pricing that represent institutional barriers to DE. These are:

- the ***level*** of prices, particularly related to unpriced 'external costs'; and
- the ***structure*** of prices.

Externalities (environmental costs/ carbon price)

External costs or externalities are costs that are associated with the supply of a good but are not included in the price of that good. The most prominent external cost of electricity supply is the cost of climate change caused by the burning of fossil fuels to generate electricity. This means that the average price of electricity is set below its true full cost of supply, leading to excessive consumption of fossil fuel-based electricity and reducing the uptake of low emission DE resources such as energy efficiency and distributed renewable energy.

The simplest mechanism to redress this barrier is to put a price on carbon through either a carbon tax or a carbon emission trading scheme as proposed by the Garnaut Review (2008) . For such a mechanism to overcome this barrier fully, the price of carbon must be set at a level high enough to cover fully the cost of the environmental harm being caused, and this price must apply to all relevant carbon emissions. A carbon price was adopted by the former Australian Labor Government in 2012, before being rescinded by the Abbott Coalition Government in 2014.

Inefficient price structures

While more subtle than excluded external costs, pricing structures can be an even greater barrier to DE than the exclusion of external costs. In particular, the Australian Energy Market Commission has repeatedly recognised that network charges to customers are ‘too imprecise to signal costs at different locations and different times with sufficient accuracy to attain all the opportunities for efficient demand side participation’, and noted that the absence of applicable metering technology is a significant barrier to accurate real-time pricing (AEMC, 2009a).

Some of the ways that inefficient price structures can create barriers to DE are described below.

Average rather than marginal cost pricing

Although interval meters and time-of-use tariffs are becoming more common in Australia, most electricity consumers, particularly smaller consumers, still pay a flat electricity tariff – that is, the same electricity price all day, every day throughout the year.[31] Flat tariffs contrast starkly with the wide variations in the costs of providing electricity, both in the wholesale (generation) price and the cost of providing peak capacity in networks.

This flat price structure creates a bias against those DE resources that are well suited to respond to these cost fluctuations, including cost fluctuations due to peak loads. While flat tariffs are sometimes defended as protecting vulnerable consumers, the effect is often to impose avoidable costs on all consumers, including vulnerable consumers, in order to pay for large investments in centralised generation and networks to meet occasional peak demand.

[31] The main exception to this rule is off peak electric water heating.

As Brown (2001, p. 1200) notes,

> because most customers buy electricity as they always have – under time-invariant prices that are set months or years ahead of actual use – consumers are not responsive to the price volatility of wholesale electricity', however 'time-of-use pricing would encourage customers to use energy more efficiently during high-price periods.

Greater use of cost-reflective, time-of-use tariffs is a key condition for encouraging greater use of DE.

Undervaluing DE options

Another impact of flat electricity tariffs for centralised electricity supply is that often, the value that decentralised energy resources can offer to support the centralised power system is not appropriately reflected in pricing arrangements for decentralised energy. Historically, in Australia there have been relatively few offers to pay providers of decentralised energy for the services and support they can offer to the wholesale electricity market, or to network businesses, in the form of local network support.

The 2009-14 regulatory determination by the Australian Energy Regulator (AER 2009a), which endorsed $17.6 billion dollars of network infrastructure investment in NSW with little regard to the potential role of decentralised energy, highlighted that there is still some way to go before decentralised energy measures are appropriately valued in the electricity supply system.

5.6.5 Regulatory barriers

As noted in above, to justify policy actions to address the institutional barriers to decentralised energy, it is generally not enough to demonstrate that a significant barrier or market failure exists, and that a viable policy solution is available. It is also important to make the case that any anticipated or unanticipated costs and consequences of the policy initiative will be outweighed by the benefits of addressing the barrier. In other words, the cure must be better than the disease.

To understand the reason for policy scepticism, one need only consider the regulatory barriers themselves. Some of the most significant institutional barriers to DE have been created as by-products of measures introduced to address other public policy objectives. Regulatory barriers fall into this category. These are barriers are created by the operation of laws and regulations. Several such potential regulatory barriers are discussed below.

Linking profits to sales volumes

One of the most prominent regulatory barriers results from the goal of limiting the abuse of market power by monopoly electricity suppliers. In the Australian context, this applies to the electricity network. Most electricity networks in Australia were until recently subject to economic regulation in the form of a cap on the maximum average price that they can charge. As network costs are mainly driven by capital costs, which are closely linked to peak demand, a network business's ***costs*** are not strongly influenced by the volume of electricity flowing though their wires (other than at times of peak demand).

By contrast, under a maximum price cap, the network business's ***revenue*** is directly related to the volume of electricity delivered (since revenue equals price multiplied by sales volume). Since profit equals revenue minus costs, this means that under a maximum price cap, the profitability of the network business is closely linked to the total sales volume. This puts the financial interests of the network business in direct conflict with any DM measures that would reduce the volume of electricity sales passing through the network. Consequently, a maximum price cap means that DM measures that reduce the amount of energy passing through the network are a threat to the profitability of the network business.

Fortunately, this linking or 'coupling' of network profitability with sales volume is easily avoided through well-designed economic regulation or price control. There are now well-established techniques for protecting both consumers and utility profitability, while simultaneously removing barriers to decentralised energy. For example, shifting regulation from a maximum price cap to a maximum revenue cap 'decouples' this link between the volume of energy throughput and profitability of the network business.

In the current round of distribution network regulatory determinations, starting with NSW in 2014, the AER decoupled network profit from sales volume by shifting from price cap to revenue cap regulation (AER 2013, p. 43). For further discussion of these issues see Dunstan et al. (2008).

Discriminatory rules and fiscal policies

There are many regulatory decisions that act as barriers to decentralised energy. Many of these have been identified in an analysis of 65 projects (Alderfer et al. 2000, cited in Brown, 2001). Examples cited in their work include 'prohibitions against uses of distributed [generation] (other than emergency backup when disconnected from the grid) and state-to-state variations in environmental permitting requirements that result in significant burdens to project developers' (Brown, 2001, p. 1200).

In 2009, the Australian Energy Market Commission released their *Review of demand-side participation in the national electricity market*, which summarised the AEMC's investigation into policies that act as barriers to decentralised energy and other forms of demand-side participation. The AEMC acknowledged that 'at present there is a strong supply-side in the National Electricity Market and the demand-side is relatively under-represented' (AEMC, 2009). The major barriers to demand-side participation that were noted by the review included:

- **The capex/opex trade-off:** The capex/opex trade-off becomes a potential barrier to DE due the different regulatory treatment of different types of costs between and during regulatory periods. For example, revenue cap regulation of network businesses provides these businesses with the ability to retain profits resulting from cost savings (or suffer losses resulting from overruns) for capital expenditure (capex). However, cost savings (or losses) for operating expenditure (opex) are only retained until the next revenue determination. Demand management measures are typically paid for with operational expenditure so this represents a barrier to DM.

  Therefore, the AEMC found that the current method for regulating revenue allowances for network businesses penalises a business that in the previous regulatory period used operating expenditure on demand-side participation as a means of efficiently deferring capital expenditure. In other words, any cost overruns resulting from operating expenditure spent on DM results in the network business *over-spending* on its operating expenditure forecast in order to *under-spend* against its capital expenditure forecast. This has the effect of making DM 'arbitrarily more expensive than a network infrastructure alternative'.

- **Incentives for innovation on demand-side participation and for connecting generators:** The AEMC also found that, 'in the absence of additional incentives, the existing economic regulation of networks, does not encourage distribution businesses to appropriately innovate to demand-side participation or embedded generation connections' (AEMC, 2009)[32].

- **Planning standards:** Network businesses are required to meet reliability planning standards. These standards typically require that the network is still able to supply all load when one or more of the network elements is out of service (i.e. an 'n-k' planning standard). There are two types of planning standards that are predominantly used: deterministic standards and probabilistic standards. The question is how to best analyse the contribution of decentralised energy when there is a requirement for redundancy ('n-k').

  The AEMC found that probabilistic planning standards are likely to encourage more efficient use of DM, because probabilistic standards are more 'amenable to handling demand-side participation with different degrees of 'firmness'' (AEMC 2009). Until recently, the majority of NEM jurisdictions applied deterministic planning standards. Probabilistic network reliability planning standards have now been applied across the NEM.

- **Complexity of the regulatory test:** The purpose of the regulatory investment test (RIT) for network businesses in the National Electricity Rules is to identify new network investments *or non-network alternative options* that maximise the net economic benefit to all those who produce, consume and transport electricity in the market. While network businesses are required to consider decentralised energy and 'non-network alternatives' where they would be cost-effective in accordance with a 'regulatory test', it is generally left to the network business to make this assessment.

  The application of the regulatory test is complex and often involves detailed economic modelling, which is beyond the resources of decentralised energy proponents to engage in, particularly in an environment where there are few precedents of decentralised energy being supported by the outcomes of the regulatory test. Cost-effective measures will be excluded if extensive and expensive analysis is required by

[32] Note that the recently announced Demand Management Incentive Scheme has gone a long way to addressing this problem. (See section 8.2.3.)

decentralised energy proponents to prove this option has the same level of reliability to meet both the technical and cultural definitions of reliability.

Network access and connection: Minimum technical standards for connection of embedded generators are inconsistent between network businesses and often unpredictable, which causes delays and increases costs for embedded generators.

5.6.6 Cultural barriers

In one sense, all the preceding institutional barriers are cultural. They reflect the way that people relate to the technology and the operation of institutions created by society. However, there is also a specific set of barriers that are more fundamentally cultural in that they directly reflect cultural values, attitudes and habits of thought and practice.

As Brown (2001, p. 1202) notes:

> Energy efficiency is not a major concern for most consumers because energy costs are not high relative to the cost of many other goods and services. In addition, the negative externalities associated with the US energy system are not well understood by the public. The result is that the public places a *low priority on energy issues* and energy efficiency opportunities. In turn, this reduces producer interest in providing energy-efficient products.

On the one hand, it can be argued that cultural values should not be considered a barrier at all, because culture values cannot be objectively assessed, so people should be simply free to consider important whatever they choose to consider important. On the other hand, the values we hold as individuals and as participants in the economy are shaped by our society and culture. Cultural values are constantly evolving. Values from the past may no longer be appropriate in the present circumstances. For example, attitudes about the desirability of centralised coal-fired electricity supply, which were formed when this was the dominant low cost technology, can become a significant barrier once technological change and environmental concerns mean that decentralised energy is now a cheaper and more preferable technology.

This is not to argue that the community is denied the benefits of decentralised energy because the community does not accord them enough priority. This would be a circular argument. Rather, the argument is that the community's collective desire to access the benefits of decentralised energy can be frustrated by particular individuals' and organisations' values and attitudes that are inconsistent with this social aspiration. For example, energy customers may desire that their utilities offer them rooftop solar and energy efficiency services, but the utility managers may have a view that it is not desirable to offer such services.

Another example is if society as a whole considers energy abundant and energy use harmless, then individuals and organisations wasting energy at their own expense is generally not a cultural problem. Conversely, if society considers the by-products of energy generation, such as greenhouse gas emission a matter of serious concern, then the inefficient use of energy by individuals and organisations becomes a legitimate target of policy consideration.

There are therefore two dimensions to the institutional barrier of cultural values. The first dimension of inappropriate cultural values is what might be called 'cultural lag', in which prevailing attitudes and values are no longer appropriate to the current circumstances. These values can be reflected in the behaviours of individuals or organisations. There is a natural tendency to base investment and other decisions on past experience, and to favour more familiar technologies and practices. This inherent conservatism represents a barrier to more innovative concepts like decentralised energy. This cultural lag can also have a powerful impact through the accumulated skills bases of organisations.

Potential examples of cultural lag include:

- a lack of state or national government attention (e.g. clear direction) for decentralised energy
- lack of media attention in opportunities associated with DE
- situations in which electricity utility investors and planners prefer network capital expenditure over DM operating expenditure, despite regulatory reforms aimed at removing bias against DM, because that is what they are familiar with
- situations in which electricity consumers perceive DM as a failure to invest in a reliable power supply, rather than as a more affordable means of providing reliable energy services.

The second dimension to inappropriate cultural values occurs when individual attitudes lead to behaviours on the part of individuals that conflict with the collective interests of society. This is the cultural dimension of the tragedy of the commons described in Section 5.6.2. For example, the prevailing value in society may be that everyone should use energy efficiently. However, if this attitude is not also reflected in personal values that '*I* will use energy efficiently', then it will not flow through to actual behaviour.

5.6.7 Interaction of barriers

It should be clear from the preceding discussion that many institutional barriers are interrelated. The final category of institutional barriers emerges from the observation that due to the interactions between them, the total impact of institutional barriers may be greater than the sum of the individual barriers.

It is much easier to overcome a single barrier than several barriers at once. Where any one of a number of barriers can obstruct a decentralised energy option from proceeding, it may be impractical to address all of them simultaneously.

Potential examples of this effect include:

- management complexity, or policy paralysis, in which the difficulties associated with coordinating action frustrate effective action
- interagency and intergovernmental discord, which is exacerbated in a federal system of government, such as Australia's, which has strong historical state government involvement in energy planning and investment.

5.7 Survey of perceptions of institutional barriers to DM

The foregoing discussion represents an analytical review of institutional barriers to decentralised energy. This section discusses empirical research that I undertook, as part of my doctoral research, with support from my ISF colleagues, to apply and test this analysis.

I designed and led the implementation of an original survey which examined how different stakeholders perceive a variety of potential institutional barriers to DM. This section explains the process and results of this DM Barriers Survey.

As described in Section 1.3.4, there is a crucial distinction between decentralised energy and DM. The survey focused on the barriers to decentralised energy in the context of decentralised energy being facilitated by demand management.

5.7.1 Survey method

The purpose of the project, ***Barriers to demand management: A survey of stakeholder perceptions,*** was to examine stakeholder perceptions on barriers to the implementation of DM (Dunstan et al., 2011e).[33]

The scope of the survey was developed in partnership with the project partners, and included the following elements:

- Collating potential barriers to implementation when considering or implementing DM projects.
- Engaging a wide range of stakeholders including from electricity retailers and generators, network service providers, DM product and service providers, government, consumers, regulators, research institutes and environmental organizations.
- Assessing subjective perceptions of barriers, rather than investigate objective barriers, in order to highlight how perceptions coincide and vary between stakeholders.

[33] This survey was undertaken with support from the Australian Alliance to Save Energy (A2SE) and the CSIRO Intelligent Grid (iGrid) research collaboration.

In the context of this research, DM was defined as load management (LM), energy efficiency (EE), distributed generation (DG) and time of use (ToU) meters and tariffs. These terms are defined below.

Table 5-2 Definitions of types of demand management

Peak load management (LM)	Includes, but is not limited to, direct load control, demand response, interruptible loads, load shifting, power factor correction (in customer premises, but not within the network), fuel substitution and integrated DM projects (which include a mix of DM types)
Energy efficiency (EE)	Primarily refers to end-use efficiency, e.g. delivering equal or greater levels of 'energy services' with less energy supply: cooling, heating, lighting, driving motors, operating equipment and appliances, etc.
Distributed generation (DG)	Refers to energy generators embedded within the network, typically less than 30MW, and includes, but is not limited to, solar photovoltaics, wind, small-scale hydroelectric, biomass/biogas, cogeneration, trigeneration, diesel, fuel cells and standby generation.
Time-of-use (ToU) meters and tariffs	These are meters that include functions to measure energy at its time of use, where data are either manually or electronically retrieved. Time-of-use tariffs are tariffs that use this time-of-use data for billing purposes, usually with the aim of influencing behaviour in regards to energy use.

The list of possible barriers presented in the survey was drawn from the analysis in Section 5.6 and complemented by a desk-top review of other studies on DM barriers, including sources such as:

- Demand-side participation in the National Electricity Market (AEMC, 2009), including reports, submissions and responses
- Demand management and planning project: final report (DMPP, 2008)
- Issues and barriers in developing trigeneration in Sydney (ISF, 2009)
- Improving energy efficiency in the National Electricity Market (ISF, 2010)
- Demand management and energy policy development: a case study of New South Wales (TEC, 2010).

It is recognised that different stakeholders encounter different barriers when seeking to implement DM. For example, the barriers experienced by a network service provider may be quite different from those experienced by a commercial customer. Recognising the differing perspectives among stakeholders, the survey was designed to present the barriers in a classification system that was relevant to as many respondents as possible. The barrier classification identified above (Figure 5-6) was adopted for the survey.

The draft DM Barriers Survey was distributed for comment to the survey project steering committee and project partners. Feedback was received from all parties and was addressed in the final version of the survey.

The DM Barriers Survey was circulated in early March 2011 and participants were given up to three weeks to respond. A link to the Intelligent Grid report *20 Policy Tools for Developing Decentralised Energy* (Dunstan et al. 2011b) was also included in the invitation to participate.

The survey was distributed to 808 demand management stakeholders from a large database derived from the CSIRO Intelligent Grid Project, as well as respondents to the Survey of Energy Network Demand Management in Australia (SENDMA), and additional DM contacts known to the research team. Hence, the survey sample was not based on a random sample of subjects.

The survey was conducted in accordance with ethical principles of the University of Technology Sydney. Ethics approval to conduct this survey was sought and received from the UTS Human Research Ethics Committee based on an adherence to the ISF Code of Ethics. The Code of Ethics was followed throughout the project, including informed consent, privacy and anonymity, and confidentiality for respondents unless consent has been given.

A total of 25 statements of potential barriers were presented for all types of DM (i.e. LM, EE, DG, ToU). An additional eight statements specifically relating to distributed generation and three relating only to time-of-use tariffs were presented. Each potential barrier was given a unique identifier and short description. The full list of statements is presented in Table 5-3 and Table 5-4 below.

Note, the colouring and the letter in each unique identifier refer to the type of barrier (Figure 5-6), as follows:

I:	Imperfect **I**nformation
S:	**S**plit Incentives
G:	Payback **G**ap
P:	**P**rice Structures
R:	**R**egulatory Barriers
B:	Cultural **B**ias
C:	**C**onfusion,

There were a further two categories of barrier identifiers specifically relating to:

D:	**D**istributed Generation
T:	Time-of-use **T**ariffs**.**

5.7.2 Institutional barriers to DM proposed in survey

Table 5-3 Presented barriers with their identification codes and short descriptions

ID	Short Description	Potential Barrier
Imperfect Information		
I1	Limited experienced / skilled DM service providers	There is a limited number of experienced and skilled DM service providers.
I2	Lack of data on costs, reliability, potential from DM precedents	There is a lack of good data about costs, reliability and potential (GWh and MW peak) from demand management precedents.
I3	Lack of information about network constraints	There is a lack of easily accessible information about network capacity constraints and DM opportunities.
Split Incentives		
S4	Competing priorities in utilities limit consideration of DM	Competing priorities and objectives within different parts of electricity supply businesses may limit adequate consideration of DM measures, so that an efficient level of DM is not implemented.
S5	Disaggregated electricity market – DM benefits hard to capture	The disaggregated structure of the electricity market (e.g. transmission is separated from distribution which is separated from retail) means the full benefits of implementing a DM measure may not be able to be captured by the initiator of the measure.
S6	Landlord–tenant relationship	The classic example of the landlord-tenant relationship is a barrier to DM. Specifically in the case of electricity supply businesses and end use customers, the financial benefit of DM could accrue to the customers, but the tenants are reluctant to pay for investment if they may not remain a customer long enough to reap the benefits.
Payback Gap		
G7	Lack of capital, financiers, funds for DM project proponents	There is a lack of capital, financiers and funds available to willing proponents of DM projects.
G8	Consumers / utilities want shorter DM payback than for supply	Consumers and electricity supply businesses typically require a shorter payback period for the investment in DM than other network investments.
G9	Utilities have easier access to finance than DM providers	Energy supply businesses have easier access to financing that will allow for investments with a long payback period (e.g. 30 - 40 years), whereas DM service providers do not have such easy access to long-term financing.

ID	Short Description	Potential Barrier
Inefficient Pricing of Energy		
P10	Lack of carbon price	The lack of a carbon price, which is an unpriced 'external cost' of energy, inhibits DM from being cost-effective.
P11	Local peak / network constraints not reflected in power prices	Locational peak demand costs, or network constraints, are not included in electricity prices.
P12	Time based prices poorly reflect time & location cost of money	Where time-of-use (cost-reflective) tariffs do exist, they do not yet fully and completely represent the cost of providing energy at a given time or location.
Regulation		
R13	Electricity suppliers profit from electricity sold, DM cuts profits	Electricity supply businesses make profit based on the amount of electricity that they sell; therefore implementing DM measures would decrease their profit (e.g. price regulation financially penalises network businesses that reduce their electricity sales volume through DM).
R14	Networks don't invest in DM unless constraint is imminent	Currently network supply businesses tend not to invest in DM unless a constraint is imminent. However, this short trigger period typically does not allow sufficient lead time for networks to be confident that large scale DM can be found or be certain will meet the system requirements.
R15	Regulatory processes (security, reliability) don't consider DM	Regulatory processes do not adequately consider DM as an alternative (e.g. the parameters on which electricity supply businesses are explicitly being regulated such as security, reliability and expenditure reviews, do not include criteria for demand management).
R16	Regulatory Test (RIT) limits assessment of DM	Investment assessment mechanisms or processes, such as the Regulatory Investment Test, are not transparent enough to allow a clear assessment of DM compared to network investment.
R17	High $ threshold of Regulatory Investment Test restricts DM	The Regulatory Investment Test (RIT) guides electricity supply businesses towards more intensive assessment and consultation processes when considering DM options for larger network investment projects, to limit the regulatory burden of applying these procedures on a large number of smaller projects. This more limited consideration of DM as an alternative to smaller augmentation projects restricts a greater volume of DM from being effectively identified and implemented.

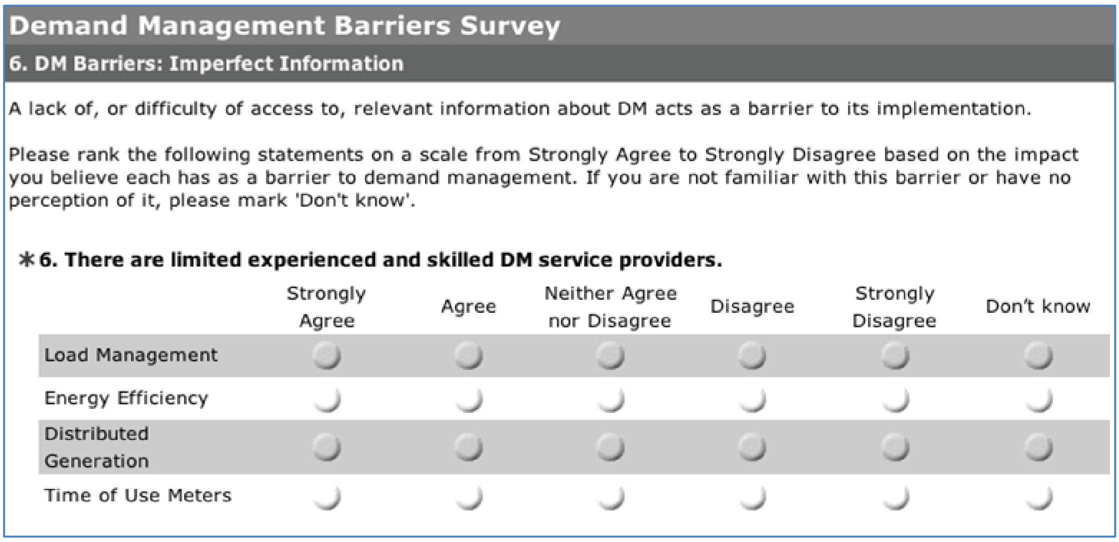
Cultural Bias		
B18	Lack of state / national government consideration for DM	There is a lack of state or national government consideration, or priority given to, demand management.
B19	Utility bias towards centralised supply	There is a cultural bias within electricity supply businesses towards business-as-usual centralised supply options, thereby disadvantaging demand management.
B20	Electricity suppliers lack expertise / experience with DM	Electricity supply businesses lack expertise and/or experience with internal demand management strategies.
B21	Absence of DM / environmental objective in National Electricity Law	There is an absence of an energy saving or environmental objective in the National Electricity Law.
B22	Electricity consumers lack interest in saving energy	Electricity consumers have a lack of interest in saving energy.
B23	Consumers want to use power when & how they choose	Electricity consumers want to use power when and how they choose and therefore they perceive DM as a failure to invest in a reliable power supply.
B24	Electricity suppliers prefer CAPEX to OPEX, DM is OPEX	Electricity supply businesses tend to prefer to spend / invest in Capital (CAPEX) over Operating Expenditure (OPEX), but DM is usually viewed as an operating expense, causing a natural bias against DM.
Confusion		
C25	Lack of coordination at state / national level	A coordinated approach to DM is lacking at a state and/or national level.

In addition to the 25 statements presented in Table 5-3 eight potential barriers specifically relating to distributed generation and three proposed barriers relating only to time-of-use tariffs were also presented in the survey.

Table 5-4 Potential barriers specific to distributed generation and time-of-use tariffs

Barriers specific to distributed generation		
D1	Negotiation framework for utilities & DG developers not developed	An effective negotiation framework between electricity supply businesses and DG developers has not yet been developed.
D2	Connection process is too complex	The connection process is too complex (e.g. costs and time for studies on impact, terms of agreement, contract negotiation, negotiation frameworks, cost-allocation models).
D3	Uncertain which costs should be charged to embedded generators	There is uncertainty over which costs can be reasonably charged to embedded generators in planning for connection.
D4	Uncertainty re: who is recipient for resultant avoided network costs	There is uncertainty over the appropriate recipient for resultant avoided network costs.
D5	Generation licensing requirements/standards complex & expensive	Generation licensing requirements and standards are complex and require fees that are disproportionate to the size of embedded generators.
D6	Uncertainty re: impact of DG connection on network performance	Minimum technical standards do not provide enough transparency and certainty for embedded generators regarding the impact of their connection on network performance and fault levels, and hence a lack of uncertainty for the allocation of any network augmentation and connection costs that may be required.
D7	Uncertainty re: who's responsible for managing power quality risks	There are risks associated with the potential power quality and fault current at different network supply nodes and questions about who should bear the responsibility for managing additional fault current needs.
D8	Concerns about local environmental impacts of DG	There are concerns about the local environmental impacts of DG.
Barriers specific to time-of-use tariffs		
T1	Emerging public resistance to ToU meters and tariffs	There is emerging public resistance towards the installation of time-of-use meters or time-of-use tariffs.
T2	Economic regulation doesn't allow for smart metering cost recovery	Economic regulation does not allow for the efficient recovery of the costs of smart metering activities.
T3	Cost-reflective tariffs difficult to implement due to uneven approach across states	Cost-reflective tariffs are too hard to implement because of the scattered implementation across states.

For each potential barrier, the respondent was asked to rank the statement on a scale from 'strongly agree' to 'strongly disagree' based on his/her perception of it as a barrier to demand management. If the respondent was not familiar with the barrier, she/he could mark 'don't know'. Additionally, each respondent was asked to rank their perception of each statement and its impact for the four types of DM technologies, including load management, energy efficiency, distributed generation, and time-of-use meters. An example statement and question is presented below.



Demand Management Barriers Survey

6. DM Barriers: Imperfect Information

A lack of, or difficulty of access to, relevant information about DM acts as a barrier to its implementation.

Please rank the following statements on a scale from Strongly Agree to Strongly Disagree based on the impact you believe each has as a barrier to demand management. If you are not familiar with this barrier or have no perception of it, please mark 'Don't know'.

***6. There are limited experienced and skilled DM service providers.**

	Strongly Agree	Agree	Neither Agree nor Disagree	Disagree	Strongly Disagree	Don't know
Load Management						
Energy Efficiency						
Distributed Generation						
Time of Use Meters						

Figure 5-7 Example of survey question

(Dunstan et al., 2011e)

To analyse the survey data, each response was scored as follows:

Strongly Agree: 2 Agree :1 Neutral: 0 Disagree: -1 Strongly Disagree: -2

To understand the differences in perceptions between the stakeholder groups, respondents were asked to identify their stakeholder type using the following categories:

- Energy Utility – Network
- Energy Utility – Retailer
- Energy Utility – Generator
- Government Agency – Federal
- Government Agency – State
- Government Agency – Local
- Energy Consumer – Commercial
- Energy Consumer – Industrial
- Demand Management Provider
- Demand Management Consultancy
- Energy Supply Consultancy
- Environmental organisation
- Consumer organisation
- Industry organisation
- Regulator
- Research Institution
- Other.

For the purposes of the analysis, these respondent types were grouped into the categories of: Utilities, Government, End User, DM Provider, and Other (see Table 5-5). At the end of the survey, respondents were also invited to submit statements in their own words on their perceptions of barriers to DM.

5.7.3 Summary of respondents

In total, 202 participants responded, with 165 participants fully completing the survey. All survey answers were used in the analysis, including partially completed surveys.

Table 5-5 Respondent numbers by type and category

Category	Respondent type	No. of Respondents	Total Respondents	% of total Respondents
Utilities	Energy Utility – Network Energy Utility – Retailer Energy Utility – Generator	29 5 1	35	18%
Government	Government Agency – Federal Government Agency – State Government Agency – Local	2 20 8	30	15%
End User	Energy Consumer – Commercial Energy Consumer – Industrial	12 2	14	7%
DM Provider	Demand Management Provider Demand Management Consultancy Energy Supply Consultancy	8 17 14	39	19%
Other	Environmental organisation Consumer organisation Industry organisation Regulator Research Institution *Other*	16 8 3 2 26 29	84	41%
	Total Respondents	**202**		

Almost one-fifth of respondents were in the category of DM providers, which includes DM consultants and energy consultants (n=39). Government and Utilities had a similar number of responses, with 36 responses from electricity utilities (retailers, networks and generators) and 30 from local, state and federal government. Fourteen respondents were End Users. The remaining respondents were placed in the category of 'Other'. The largest single type of respondent was electricity networks (n=29) followed by state government (n=20).

The survey was circulated to a pre-existing nationwide database of DM stakeholders; therefore the responses are broadly representative of the DM and the related industry, rather than the general population. The majority of respondents (42%) indicated that DM was a significant part of their work, 37% indicated DM was a minor part of their work, and a further 20% indicated that they were interested in DM even though it was not a part of their work. Only 1% (n=2) of respondents indicated that they did not have a significant interest in DM.

Respondents also had a significant amount of experience in DM, with 36% (n=70) of respondents working in the industry for two to five years, 20% (n=38) for five to ten years, and 27% (n=52) for ten or more years. Less than a fifth of the respondents worked in the industry less than two years (17%, n=33).

As shown in Figure 5-8, the majority of responses came from NSW (33.2%, n=66), Victoria (22.8%, n=46) and Queensland (18.3%, n=37), with all other states and territories represented.

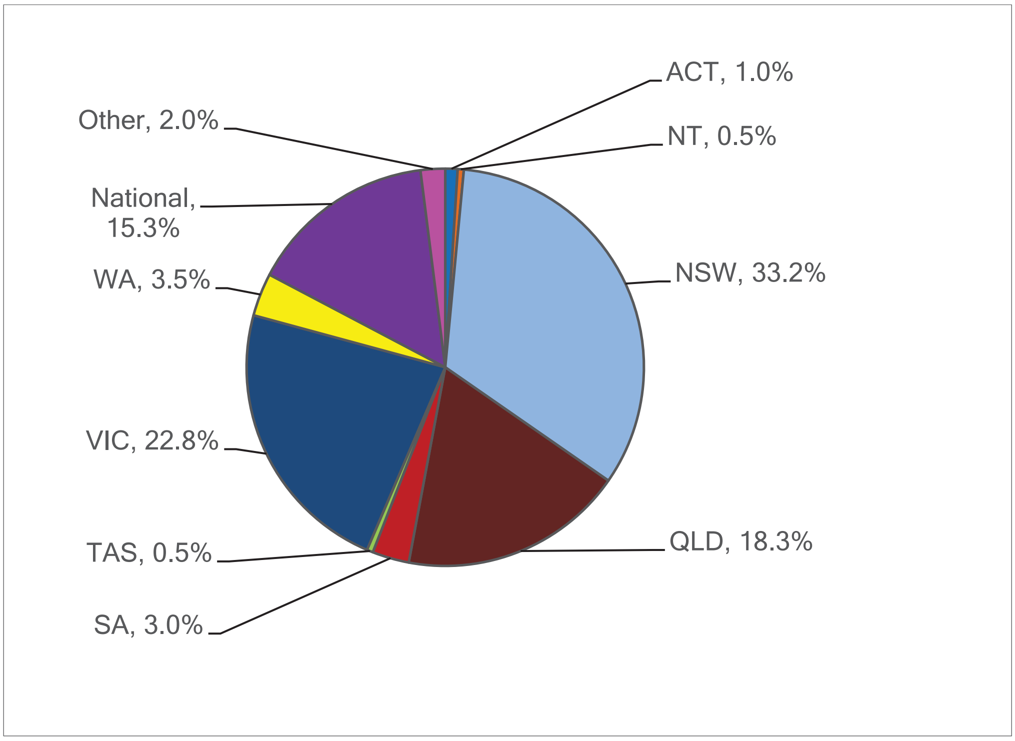


Figure 5-8 Proportions of respondents in each jurisdiction

(Dunstan et al., 2011e)

5.8 Comparing perceptions of barriers to DM

In this section, the perceptions of barriers are compared across barrier categories, respondent types and DM technology types.

5.8.1 Perceived barriers by category

A total of 25 general barriers were proposed in the survey, and each of these was placed into one of seven categories, as shown in Table 5-3. A weighted average was calculated for each barrier category, as shown in Figure 5-9 below.[34]

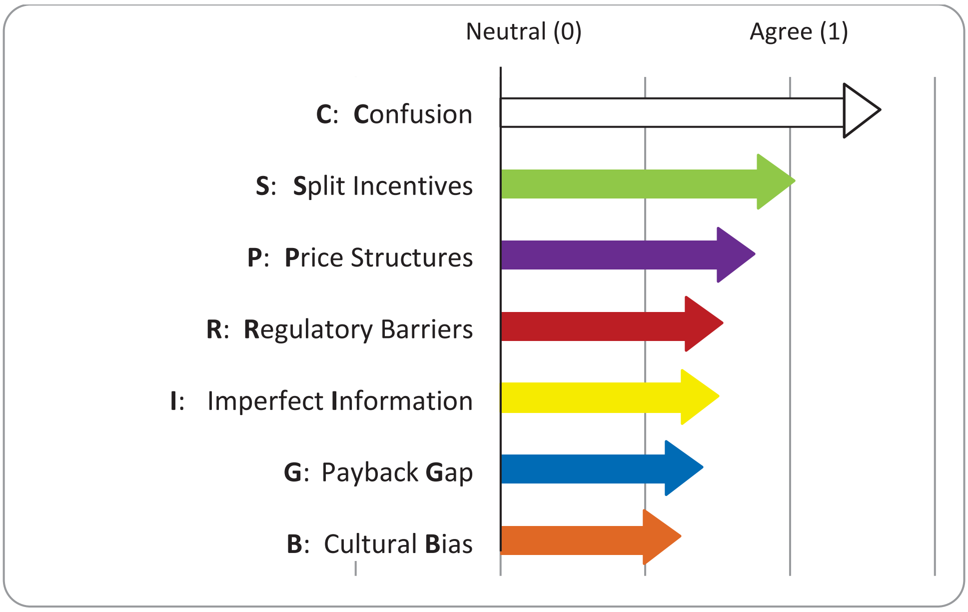


Figure 5-9 Agreement / disagreement to proposed DM barriers by barrier category (Dunstan et al., 2011e)

The Confusion category received the highest level of agreement as representing barriers to DM, followed by barriers categorised as Split Incentives, and Inefficient Pricing of Energy. Barriers in the area of Cultural Bias had some strong agreement and some strong disagreement, and it is therefore closer to neutral agreement than the other categories.

[34] The weighted averages include the averages across respondents, DM technologies and each barrier within the category.

To complement the comparative analysis of the seven barrier categories in Figure 5-9, a qualitative grouping into the seven categories was completed for the 150 additional barriers to DM that were suggested by survey respondents.

An average of the responses was also calculated for each of the 25 proposed barriers. These weighted averages are presented in Figure 5-10 in order to compare the comparative strength of the agreement with each barrier. Each barrier is labelled with the unique identifier introduced in Table 5-3 (for example, 'I1' refers to '*There are limited experienced and skilled DM service providers*'). Figure 5-10 arranges the proposed barriers in the same format as the Barriers Spectrum in Figure 5-6. The centre of the radial diagram represents 'Disagree' (score -0.5) and each incremental circumference out from the centre represents an increased degree of agreement.

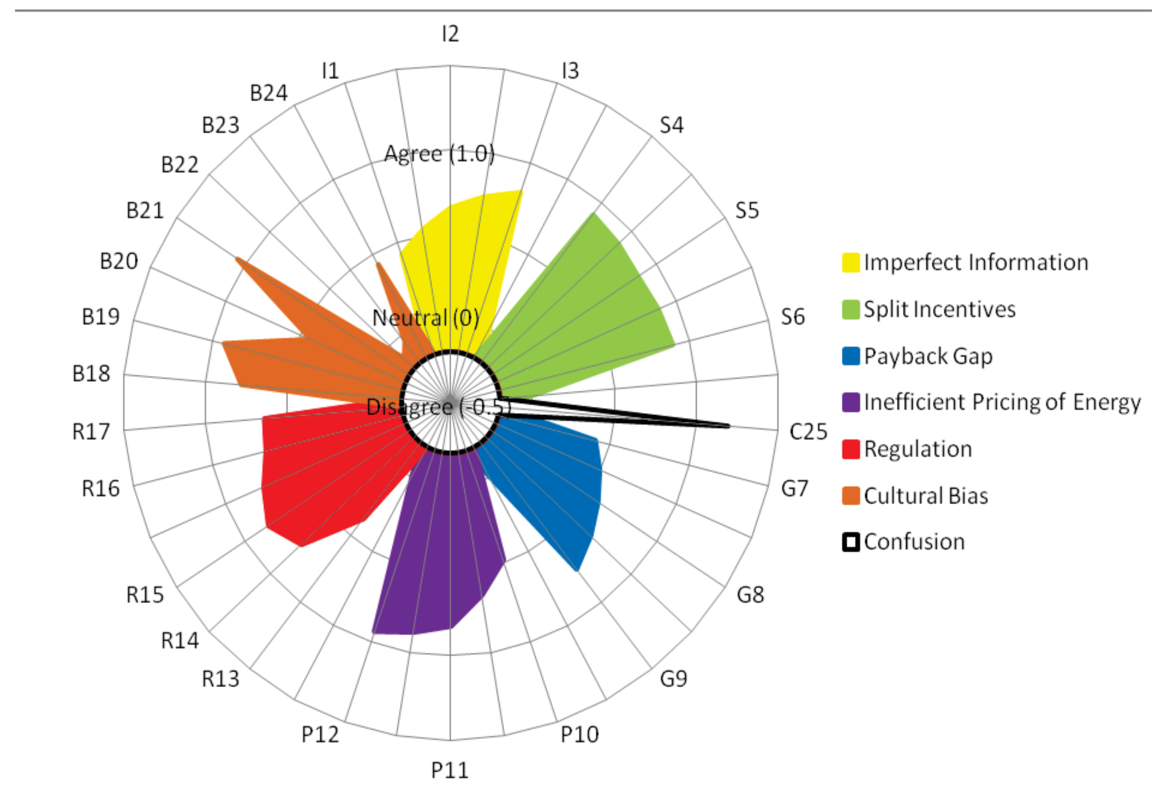


Figure 5-10 Relative strength of agreement for each barrier (by category)
(Dunstan et al., 2011e)

The highest degree of agreement was with the barrier statement pertaining to Confusion, in particular, '*A coordinated approach to DM is lacking at a state and/or national level*' (C25). Proposed barrier B21, or '*There is an absence of an energy saving or environmental objective in the National Electricity Law*' had the second-highest level of agreement.

Also shown in Figure 5-10, barriers pertaining to Split Incentives, or situations where the potential proponents of DM are unable to receive the full benefits of implementing DM, received consistently average levels of agreement. This response on was fairly consistent across all respondent types and technology types, for the three barriers in the Split Incentives barrier category: '*Competing priorities in utilities limit consideration of DM*' (S4), '*Disaggregated electricity market – DM benefits hard to capture*' (S5), and '*Landlord-tenant relationship*' (S6).

Figure 5-10 also demonstrates that, comparatively, respondents were more neutral in their perceptions of barriers pertaining to the Payback Gap – that is, barriers associated with the differences in DM payback periods or payback expectations.

Perceptions by respondent category

The weighted averages were also calculated for each respondent category: Utility, Government, End User, DM provider and Other. Figure 5-11 presents the averages for each barrier, as well as the means for all responses.

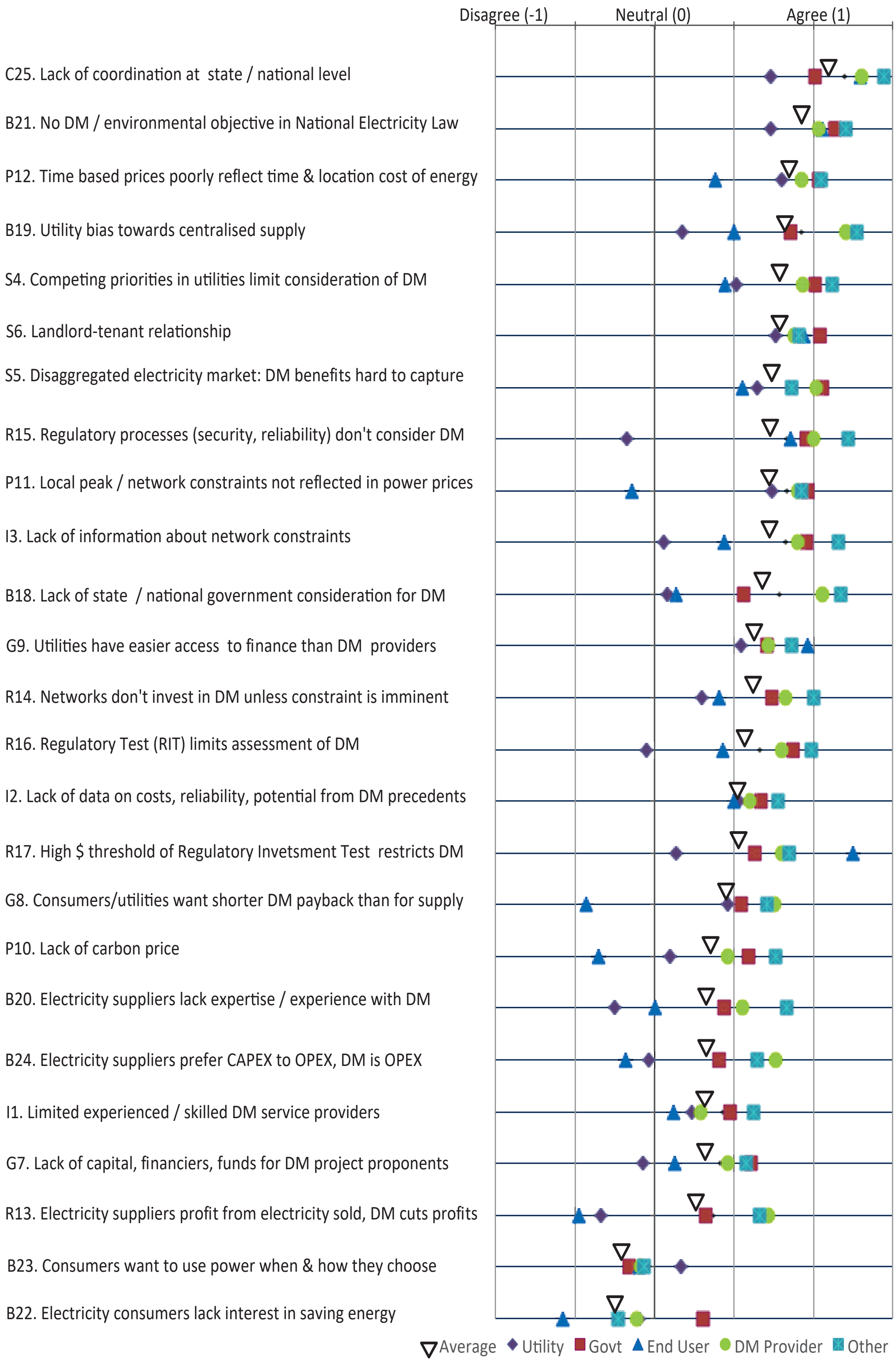


Figure 5-11 Barriers in order of agreement / disagreement by respondent category
(Dunstan et al., 2011e)

The average of all respondents agreed that all of the presented statements were barriers to DM, except for two statements regarding consumer attitudes (B22 and B23). However, there were some proposed barriers for which End Users and Utilities disagreed with the majority of respondents. Utilities respondents disagreed with some of the proposed barriers in the areas of Cultural Bias, Regulation and Payback Gap. End Users disagreed with some of the proposed barriers in the areas of Cultural Bias, Inefficient Pricing of Energy, Regulation and Payback Gap.

Figure 5-11 indicates that the category of barrier with the highest average level of agreement pertained to Confusion, and in particular, '*A coordinated approach to DM is lacking at a state and/or national level*' (C25). The second-most universally endorsed barrier was '*There is an absence of an energy saving or environmental objective in the National Electricity Law*' (B21).

The most disagreed-with group of barriers was Cultural Bias, particularly '*Electricity consumers have a lack of interest in saving energy*' (B22), followed by '*Electricity consumers want to use power when and how they choose and therefore they perceive DM as a failure to invest in a reliable power supply*' (B23). These were the only two proposed barriers that the majority of respondents disagreed with.

For End Users, DM Providers and Others, '*Lack of coordination at state / national level*' (C25) was the barrier that received the highest level of agreement. End Users also had a high level of agreement that '*Higher $ threshold of Regulatory Investment Test restricts DM*' (R17) is a barrier to DM.

Utilities had highest agreement on barriers relating to inefficient pricing of energy and split incentives. Utilities had stronger agreement on '*Time based prices poorly reflect time and location cost of energy*' (P12), '*Local peak / network constraints not reflected in power prices*' (P11) and '*Landlord-tenant relationship*' (S6) ahead of (C25).

Government respondents most strongly agreed that the '*Absence of DM / environmental objective in National Electricity Law*' (B21) is a barrier to DM.

Barriers with the strongest disagreement within each respondent category

Government most strongly disagreed with the proposition that '*Consumers want to use power when and how they choose*' (B23) is a barrier to DM.

DM providers, End Users, and Others most strongly disagreed with '*Electricity Consumers lack interest in saving energy*' (B22).

Utilities had strongest disagreement with '*Electricity suppliers profit from electricity sold, DM cuts profits*' (R13) as being a barrier to DM, as well as '*Electricity suppliers lack expertise / experience with DM*' (B20) and '*Regulatory processes (security, reliability) don't consider DM*' (R15).

Barriers with the most similar perceptions across respondent type

The proposed barriers with the most uniform levels of perception across all respondent types were '*Lack of data on costs, reliability, potential from DM precedents*' (I2) and the '*Landlord-tenant relationship*' (S6), in that all types of respondents agreed, to similar levels, that these statements are about barriers to DM.

Barriers with the most divergent responses from respondent types

The barrier with the widest divergence in perceptions among respondents was '*Regulatory processes (security, reliability) don't consider DM*' (R15), with Utilities slightly disagreeing and all other respondents agreeing. Other barriers with dissimilar perceptions included '*Electricity suppliers profit from electricity sold, DM cuts profits*' (R13) and '*Consumers / utilities want shorter DM payback than other for supply*' (G8).

5.8.2 Perceived barriers by technology type

The weighted averages were also calculated for each DM technology type: LM, EE, DG, and ToU. Figure 5-12 presents these weighted averages for each barrier, as well as the mean for all responses.

On average, respondents agreed that all of the proposed statements were barriers for each type of DM, except '*Electricity Consumers lack interest in saving energy*' (B22) and '*Consumers want to use power when and how they choose*' (B23).

The strongest agreement was again with '*Lack of coordination at state / national level*' (C25), which was a barrier for all DM technology types, and with '*Absence of DM / environmental objective in National Electricity Law*' (B21).

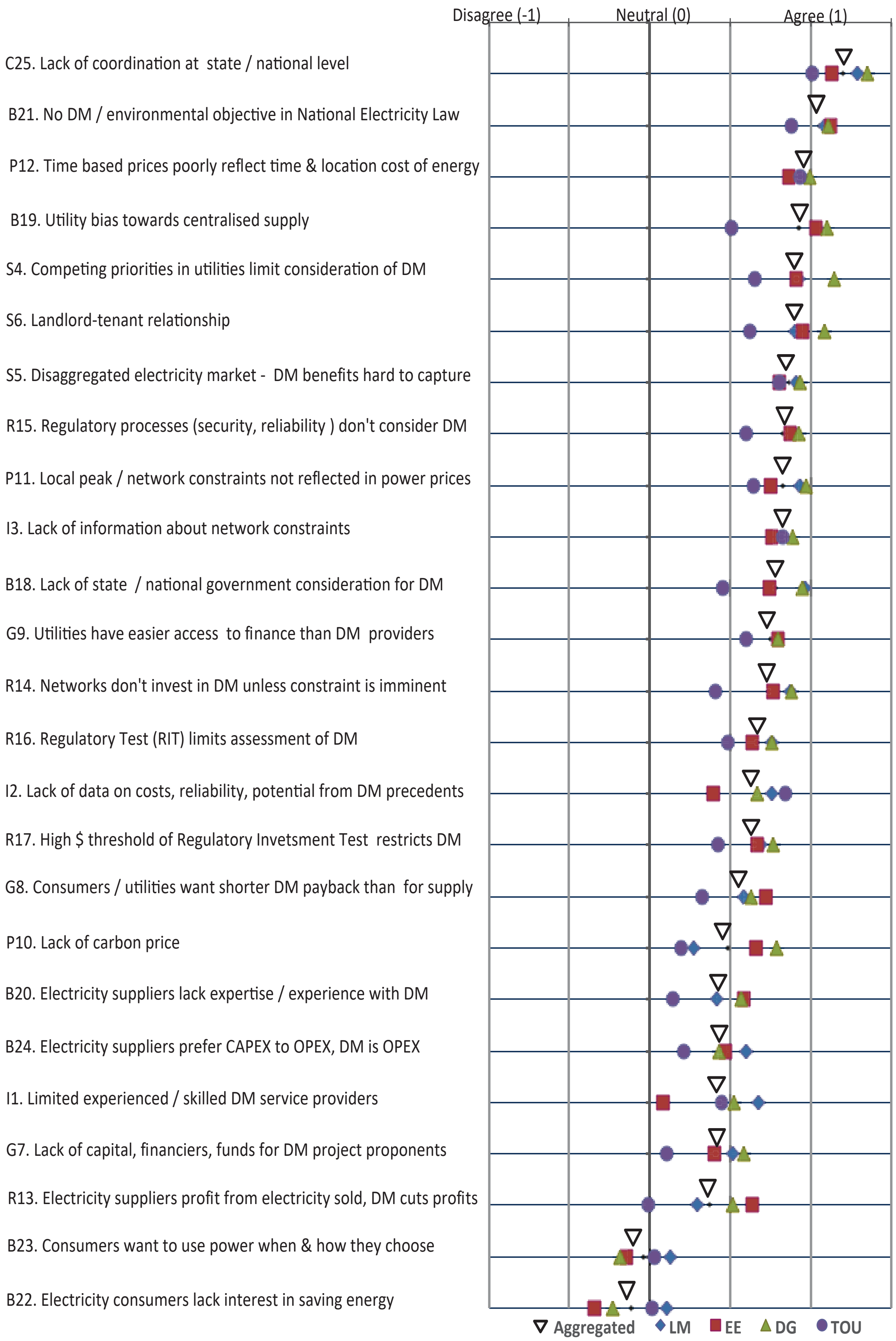


Figure 5-12 List of barriers in order of agreement / disagreement by technology type (Dunstan et al., 2011e)

As a reference for the following sections, which present the barriers by each DM type, Table 5-6 presents short descriptions and unique identifiers for each barrier.

Table 5-6 Identifier and short description of proposed barriers

Imperfect Information	
I1	Limited experienced / skilled DM service providers
I2	Lack of data on costs, reliability, potential from DM precedents
I3	Lack of information about network constraints
Split Incentives	
S4	Competing priorities in utilities limit consideration of DM
S5	Disaggregated electricity market - DM benefits hard to capture
S6	Landlord-tenant relationship
Payback Gap	
G7	Lack of capital, financiers, funds for DM project proponents
G8	Consumers / utilities want shorter DM payback than for supply
G9	Utilities have easier access to finance than DM providers
Price structures	
P10	Lack of carbon price
P11	Local peak / network constraints not reflected in power prices
P12	ToU tariffs don't represent time / location cost of energy
Regulatory Barriers	
R13	Electricity suppliers profit from electricity sold, DM cuts profits
R14	Networks don't invest in DM unless constraint is imminent
R15	Regulatory processes (security, reliability) don't consider DM
R16	Regulatory Test (RIT) limits assessment of DM
R17	High $ threshold of Regulatory Investment Test restricts DM
Cultural Bias	
B18	Lack of state / national government consideration for DM
B19	Utility bias towards centralised supply
B20	Electricity suppliers lack expertise / experience with DM
B21	Absence of DM / environmental objective in National Electricity Law
B22	Electricity consumers lack interest in saving energy
B23	Consumers want to use power when & how they choose
B24	Electricity suppliers prefer CAPEX to OPEX, DM is OPEX
Coordination	
C25	Lack of coordination at state / national level

Proposed barriers relating specifically to Distributed Generation	
D1	Negotiation framework for utilities & DG developers not developed
D2	Connection process is too complex
D3	Uncertain which costs should be charged to embedded generators
D4	Uncertainty re: who is recipient for resultant avoided network costs
D5	Generation licensing requirements/standards complex & expensive
D6	Uncertainty re: impact of DG connection on network performance
D7	Uncertainty re: who's responsible for managing power quality risks
D8	Concerns about local environmental impacts of DG
Proposed barriers relating specifically to Time-of-Use Tariffs	
T1	Emerging public resistance to ToU meters and tariffs
T2	Economic regulation doesn't allow for smart metering cost recovery
T3	Cost-reflective tariffs difficult to implement due to uneven approach across states

5.8.3 Barriers for load management

In relation to Load Management, on average respondents agreed with all of the proposed DM barriers, including the two most disagreed-with barriers in relation to other types of DM. The most agreed-with barrier was '*Lack of coordination at state/national level*' (C25), which consistently rated highest across all areas of DM.

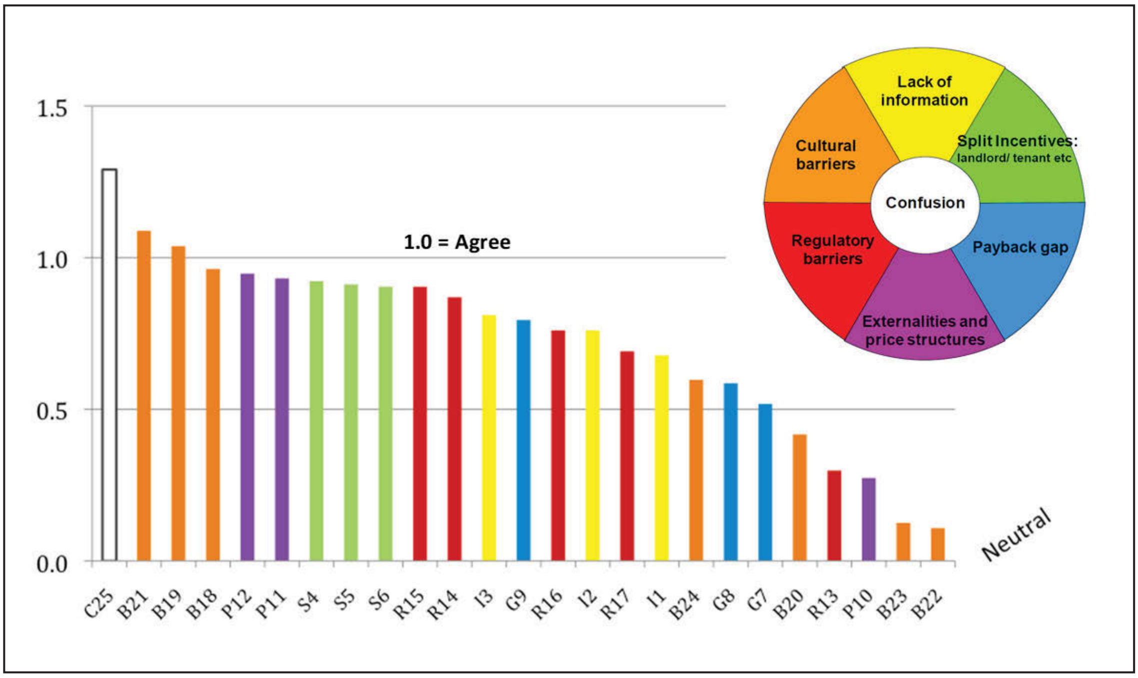


Figure 5-13 Agreement / disagreement to proposed barriers for LM
(Dunstan et al., 2011e)

After C25, the next three most agreed-with barriers were in the area of Cultural Bias:

- 'Absence of DM / environmental objective in National Electricity Law' (B21)
- 'Utility bias towards centralised supply' (B19)
- 'Lack of state / national government consideration for DM' (B18).

The fifth-most agreed-with barrier regarding LM was in the area of Inefficient Pricing of Energy, that is, '*Time based prices poorly reflect time and location cost of energy*' (P12).

5.8.4 Barriers for energy efficiency

For Energy Efficiency, the range of responses was wider compared to Load Management. The most agreed-with barrier was consistent with all other areas of DM: '*Lack of coordination at state/national level*' (C25). This was followed closely by the next two most agreed-with barriers in the area of Cultural Bias: '*Absence of DM / environmental objective in National Electricity Law*' (B21) and '*Utility bias towards centralised supply*' (B19).

The next two most agreed-with barriers for Energy Efficiency were in the area of Split Incentives: '*Landlord-tenant relationship*' (S6), and '*Competing priorities in utilities limit consideration of DM*' (S4). These barriers rated highly for Energy Efficiency compared to other areas of DM.

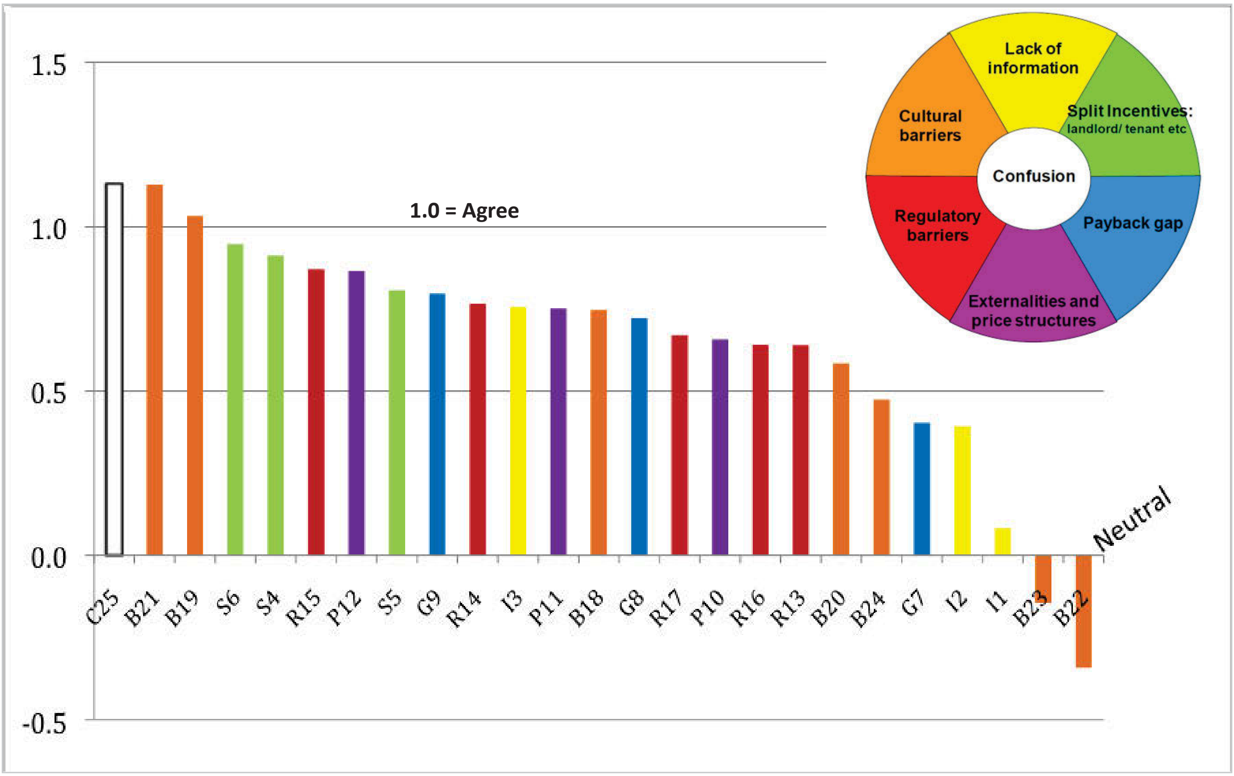


Figure 5-14 Agreement / disagreement to proposed barriers for EE
(Dunstan et al., 2011e)

One respondent summarised the main barriers to energy efficiency as 'the absence of any environmental constraint in the NEM; a structural bias towards increasing sales and throughput as a way of making profit at every step of the supply chain; weak national EE regulation; absence of EE targets; in some sectors, absence of carbon pricing'.

Additional comments about energy efficiency policies that were submitted by respondents related to topics that ranged from the delivery of energy efficiency policies to the level of its profile. Here are a few examples:

- Government policies for energy efficiency quite often adversely affect the demand curve of the network delivery business. For example, the move away from electric hot water systems. This program is seeing previously managed load move to being unmanaged. Solar hot water and heat pumps are adding to the demand curve in winter, as the electric boost elements in solar are larger than the previous cylinder systems that were charged in off peak.
- Potential risk of energy efficiency measures not delivering as promised
- Lack of high profile given to energy efficiency – not as sexy as PV etc.

5.8.5 Barriers for distributed generation

The most agreed-with barrier for Distributed Generation was again, '*Lack of coordination at state/national level*' (C25). This was followed by a barrier in the area of Split Incentives '*Competing priorities in utilities limit consideration of DM*' (S4), and a barrier in the area of Cultural Bias: '*Absence of DM / environmental objective in National Electricity Law*' (B21).

The fourth-most agreed-with barrier was one pertaining particularly to Distributed Generation, namely '*Connection process is too complex*' (D2), followed by another Cultural Bias barrier '*Utility bias towards centralised supply*' (B19).

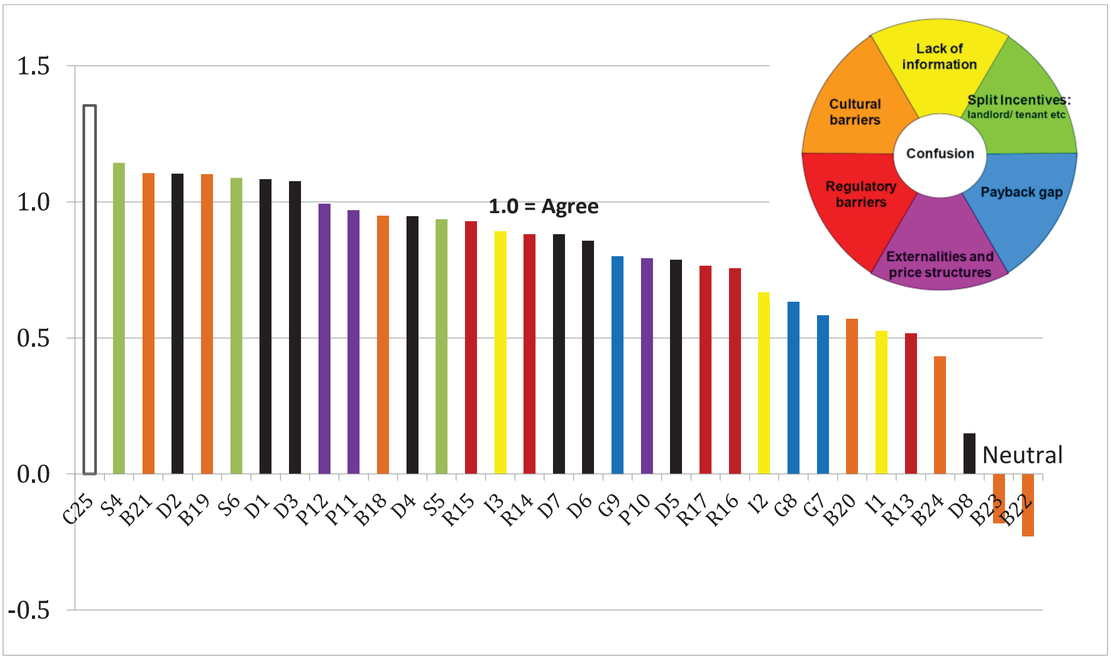


Figure 5-15 Agreement / disagreement to proposed barriers for DG

(Dunstan et al., 2011e)

The responses with the highest levels of agreement in the whole survey were in the area of Distributed Generation, with eight barriers above the 'Agree' threshold, compared to three for LM and EE, and one for ToU.

Several additional comments by respondents regarding barriers specific to DG reinforced the view that a lack of incentives was a major barrier:

- The lack of federal, long-term feed-in tariffs, subsidies and other **incentives** impedes adoption of DG, storage and DM initiatives at the residential and small business level.
- **Uncertainty and lack of incentives** for embedded generation (such as medium-scale distributed solar) limit its application. (This is closely linked to issues around the inability to capture the network benefits of the technology, i.e. avoided network infrastructure and avoided transmission and distribution network charges, etc.; as well as the lack of cost-reflective pricing, both in terms of ToU and carbon costs. While "lack of incentives" is not itself a barrier, it is noted here as a proxy for the need for policy solutions, since incentives may be a preferred way to overcome these other barriers.)
- National electricity rules need to be amended to allow for fair use of system charges to distributed generation - thereby avoiding transmission (TUoS) charges altogether.

Additional comments about barriers specific to DG included:

- **Sheer range of stakeholders** involved in implementing 'precinct' level energy supply & demand solutions
- Regulations need to be changed to allow distributed generation to sell directly to local customers and thereby not be **subject to low wholesale prices for exported electricity**.
- For distributed renewable energy generation the **upfront cost** of setting up a substation and connecting to the grid is a major constraint. This substation then becomes the **property of the Distribution Company**.
- **Cost of participating in the NEM** for small generators is prohibitive (need a DE License regime).
- Reluctance of Property Developers of high density residential and commercial buildings to install cogeneration units and hot/cold water pipes for space heating and cooling as it **adds to complexity, cost and risk** for them; Owners corporations reluctant to take on risk as it requires third party service party provider; economic viability of building cogeneration units versus 'district' cogeneration and future apartment owners reluctant to take on management.
- Generally '**Registration processes** & requirements for DG' and 'Lack of transparency of **process for connection**' and specifically 'Processes and charges for registration of DG in the NEM are there regardless of whether you want to register 100kW or 2,000MW. This is too complex and far too burdensome on smaller DG installations.'
- **Inability to transfer electricity** across licensed boundaries that limits DG operability and economics
- Unclear view of how precincts and use of public networks to **export energy** should be handled
- Network businesses earn revenue only from consumers of energy. The lack of a use of system charge for generators means that distribution businesses will always have a **fundamental commercial bias to serving load and limiting distributed generation** (that may offset load or at best provide no return). If distribution businesses earned some proportion of revenue from generators (within and outside their system) they

could also have incentives to amortise the costs of upgrades to facilitate DG at their own cost.

- **Control** of DG equipment (e.g. the wind does not always be so kind when you might need it most).
- Uncertainty regarding accessing customers for, and regulation of, the sale price of thermal energy from distributed generation.

Three comments specific to gas and bioenergy were:

- **Gas transportation tariffs** are not ToU-based and very archaic in structure, do not support DG
- **Gas availability** at potential DG sites
- Bioenergy is generally poorly perceived by electricity retailers, and refusal to trade in wood waste RECs, even if accredited, act as a barrier. (Not even talking about native forests here).

5.9 Policy implications

The survey of stakeholder perceptions of barriers to demand management illustrates how the barriers spectrum can be a useful tool for classifying institutional barriers. The results of the survey reveal a diverse but coherent set of perspectives, with a relatively high degree of agreement on many barriers relating to high level policy coordination, pricing and data, and significant divergence on others, reflecting stakeholder groups' differing perception of their own and others' motivations and priorities, particularly between end users and utilities.

These results indicate that there is a strong constituency across stakeholders for specific priority policy reforms to support DM in *some* areas, but also that there is a need for strengthening mutual understanding between stakeholders in the electricity sector about barriers in other areas. Chapter 6 discusses conceptually how policy tools could be applied to support both these two agendas, while Chapter 8 proposes specific reforms to achieve this in the Australian National Electricity Market.

Chapter 6. The Policy Palette: Categorising Policy Tools

6.1 Introduction

If the benefits of the widespread use of decentralised energy technologies are, as highlighted in Chapter 2, so substantial, how can we as a society tap these benefits? In particular, what are the policy options that can be adopted by government to encourage Demand Management to unlock this decentralised energy potential? These questions are the focus of this chapter.

Following on from Chapter 5 which examined the institutional barriers to the efficient use of decentralised energy and DM, this chapter considers policy tools to redress those barriers. It does this in three steps:

- a brief review of the literature on classifying policy tools to support DM and decentralised energy
- a proposal for a novel approach to classifying policy tools in the form of the 'Policy Palette'
- the application of the Policy Palette to a detailed case study of policy tools to support DM in the Australian electricity sector

Although DM has been applied by electricity utilities in Australia and overseas since at least as early as the 1930s, the development of deliberate government policy to support DM only started to emerge in the 1970s. Since then, numerous policy tools have been proposed and applied for this purpose around the world. The diversity of these policy tools may itself have slowed the application of effective DM policy by creating uncertainty and confusion about which is the optimal policy tool or mix of policy tools.

In order to enhance the understanding of the applicability of various policy tools, and to assist policy makers in policy design and implementation, this chapter proposes and applies a simple, practical classification of policy tools, the 'Policy Palette'.

While the Policy Palette classification of policy tools has been developed to be applied in the specific context of this study to address institutional barriers to electricity DM, the structure of the Policy Palette is generic and can be applied to any circumstance of a market operating inefficiently due to institutional barriers. As practically all real world markets have such inefficiencies, the Policy Palette therefore has a very wide potential application.

Before classifying policy tools, it is useful to clarify how they fit within the broader context (Bawden and Freeman, 2007). Considine (1994, p. 3) describes public policy as 'an action which employs governmental authority to commit resources in support of a preferred value'. As noted in Chapter 1, *demand management is the deliberate effort to reduce or shift load by consumers as an alternative to providing additional supply.*

In the case of the electricity system, demand management facilitates the adoption of decentralised energy. The relationship between demand management, decentralised energy and policy tools to support DM and decentralised energy is illustrated in Figure 6-1.

ACTOR	ACTION	OUTCOME
Policy makers	Change **Policy *tools***	**High level drivers of behaviour change**
Utilities	Apply **Demand Management**	**DM Planning and procurement**
DE service providers	Provide **Decentralised Energy *Resources***	**DE delivery**
Consumers	Adopt **Decentralised Energy *Resources***	**Cost and emission reduction** (reduced/ changed energy use)

Figure 6-1 Relationship of policy tools to demand management and decentralised energy

As illustrated, while utilities are by definition the key actor in applying DM, there are a number of other key actors and actions required in ensure DM is effective. These include:

- the policy makers and regulators that establish the policy tools (rules, incentives, funding, program, etc.) to stimulate the utilities to apply DM

- the DE service providers who provide the decentralised energy that is the immediate focus of the utilities DM programs
- the energy consumers that adopt the decentralised energy measures (conserving energy, replacing inefficient equipment with more efficient equipment, shifting demand, using batteries for storage, installing local generation, etc.)

A DM program itself comprises a number of elements, defined as follows:

- **A measure** is a specific DE action to reduce peak demand or energy consumption (these can be technological, operational or behavioural).
- **A program tool** is a means of stimulating a measure to be implemented (e.g. incentives, information or facilitation)
- **An option** is a DE measure combined with a DM program tool. That is:

  Measure + Tool = Option

- **A program:** Several options can be combined to from a program (Dunstan et al., 2017).

6.2 Classifying policy tools

There have been numerous approaches to collating and analysing policy tools to support DM, and DE (and in particular, energy efficiency). For example, the IEA maintains very large international ***Policies and Measures Databases*** for Energy Efficiency, Renewable Energy and Addressing Climate Change (IEA, 2017). This database covers more than 50 countries and for the United States alone, includes 180 current and previous policies and measures in support of energy efficiency. In this database, the IEA uses the following energy policy type classification:

1. information and education
2. economic instruments
3. policy development and reform
4. research, development and deployment (RD&D)
5. regulatory instruments
6. voluntary approaches.

The Institute for Global Environmental Strategies classifies policies as shown in Figure 6-2.

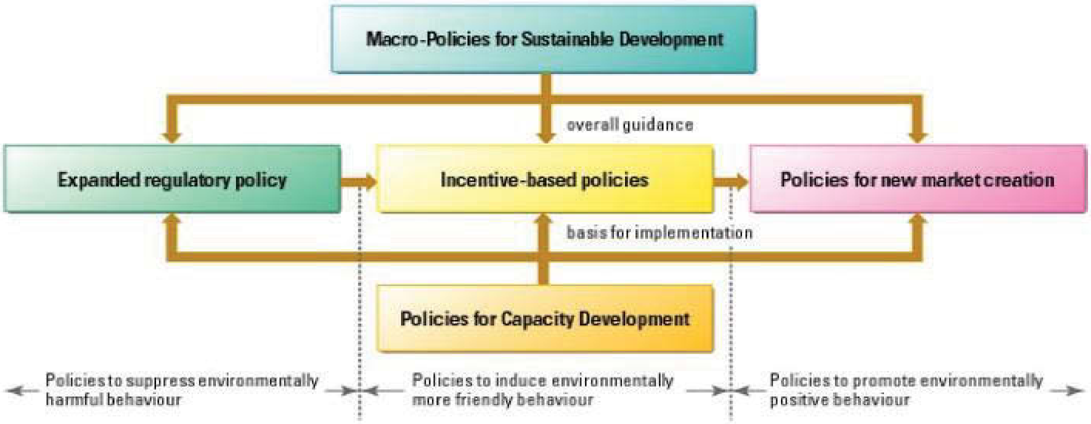


Figure 6-2 Classification of policies for innovation

(Institute for Global Environmental Strategies, 2004)

While at first glance this may seem very different to the IEA taxonomy, on closer inspection the similarity of themes is evident, with the common themes of the 'stick' of regulation, the 'carrot' of incentives, the 'signpost' of information, and arguably, the 'grease' of facilitation.

In a broad review of energy efficiency obligation policies in 19 countries, the Regulatory Assistance Project provides the following comparison of the cost of a range of energy saving policies in Denmark. While it does not formally classify policy options, Figure 6-3 shows that there can be a range of levels of cost-effectiveness for similar types of policy tools. Compare, for example, the cost-effectiveness of the energy labelling of buildings with the energy labelling of appliances.

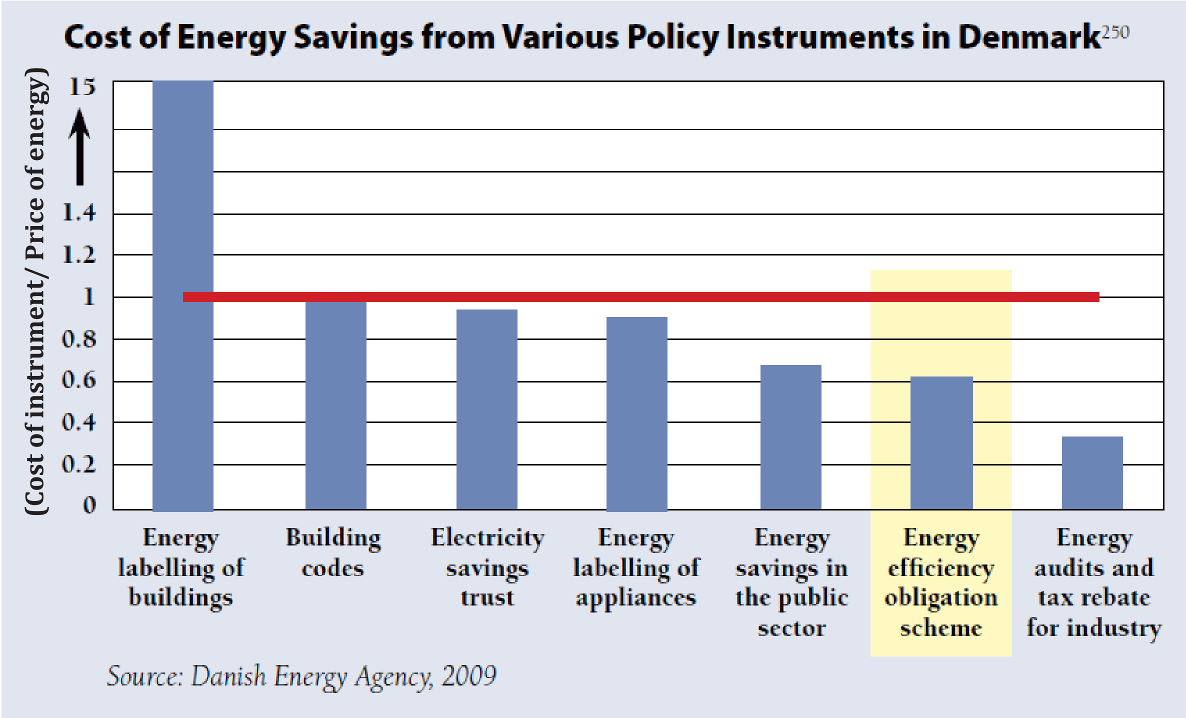


Figure 6-3 Cost of energy savings from various policy tools in Denmark

(Regulatory Assistance Project, 2012)

In response to the 2005 Gleneagles Plan of Action on Climate Change, Clean Energy, and Sustainable Development, developed by the G8 (the group of 8 major industrialised nations), in 2008 the International Energy Agency published a detailed suite of 25 policy recommendations to promote energy efficiency improvement in member countries. These recommendations are listed in Table 6-1 below. While only the last of these, Recommendation 25, relates explicitly to demand management, the policy tools reflect the range of policy types, including regulation, information, market instruments, monitoring and reporting and facilitation.

In 2011, the IEA reported on progress in implementing these recommendations across 28 IEA member countries. The outcome of this review for Australia is shown in Figure 6-4 and Figure 6-5. Australia was found to have a middling performance of implementing energy efficiency policies, ranking 11th out of 28 countries.

Table 6-1 IEA policy recommendations to promote energy efficiency

1. ***Cross sectoral:*** The IEA recommends action on energy efficiency across sectors. In particular, the IEA calls for action on:

    1.1 Measures for increasing investment in energy efficiency;

    1.2 National energy efficiency strategies and goals;

    1.3 Compliance, monitoring, enforcement and evaluation of energy efficiency measures;

    1.4 Energy efficiency indicators;

    1.5 Monitoring and reporting progress with the IEA energy efficiency recommendations themselves.

2 ***Buildings:*** Buildings account for about 40% of energy used in most countries. To save a significant portion of this energy, the IEA recommends action on:

    2.1 Building codes for new buildings;

    2.2 Passive energy houses and zero energy buildings;

    2.3 Policy packages to promote energy efficiency in existing buildings;

    2.4 Building certification schemes;

    2.5 Energy efficiency improvements in glazed areas.

3. ***Appliances:*** Appliances and equipment represent one of the fastest growing energy loads in most countries. The IEA recommends action on:

    3.1 Mandatory energy performance requirements or labels;

    3.2 Low-power modes, including standby power, for electronic and networked equipment;

    3.3 Televisions and ''set-top'' boxes;

    3.4 Energy performance test standards and measurement protocols.

4. ***Lighting***: Saving energy by adopting efficient lighting technology is very cost-effective. The IEA recommends action on:

    4.1 Best practice lighting and the phase-out of incandescent bulbs;

    4.2 Ensuring least cost lighting in non-residential buildings and the phase-out of inefficient fuel-based lighting.

5. ***Transport*** About 60% of world oil is consumed in the transport sector. To achieve significant savings in this sector, the IEA recommends action on:

    5.1 Fuel-efficient tyres;

    5.2 Mandatory fuel efficiency standards for light-duty vehicles;

    5.3 Fuel economy of heavy-duty vehicles;

5.4 Eco-driving.

6. ***Industry:*** In order to improve energy efficiency in industry, action is needed on:

6.1 Collection of high quality energy efficiency data for industry;

6.2 Energy performance of electric motors;

6.3 Assistance in developing energy management capability;

6.4 Policy packages to promote energy efficiency in small and medium-sized enterprises.

7. ***Utilities:*** Energy utilities can play an important role in promoting energy efficiency. Action is needed to promote:

7.1 Utility end-use energy efficiency schemes

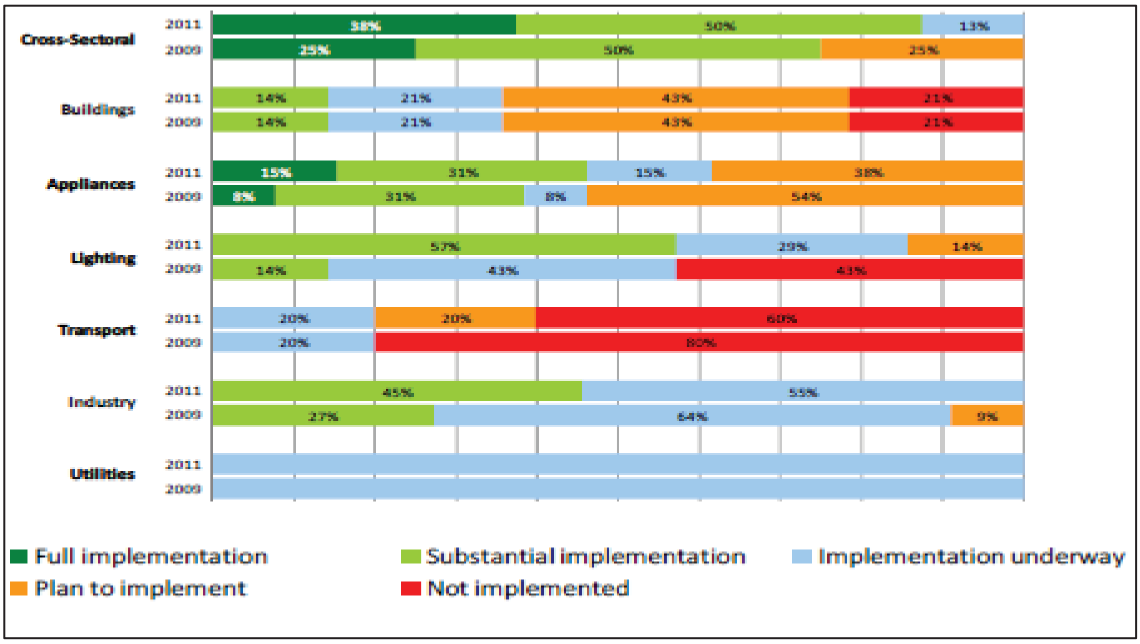


Figure 6-4 Australia's progress with implementing IEA energy efficiency recommendations (IEA, 2012)

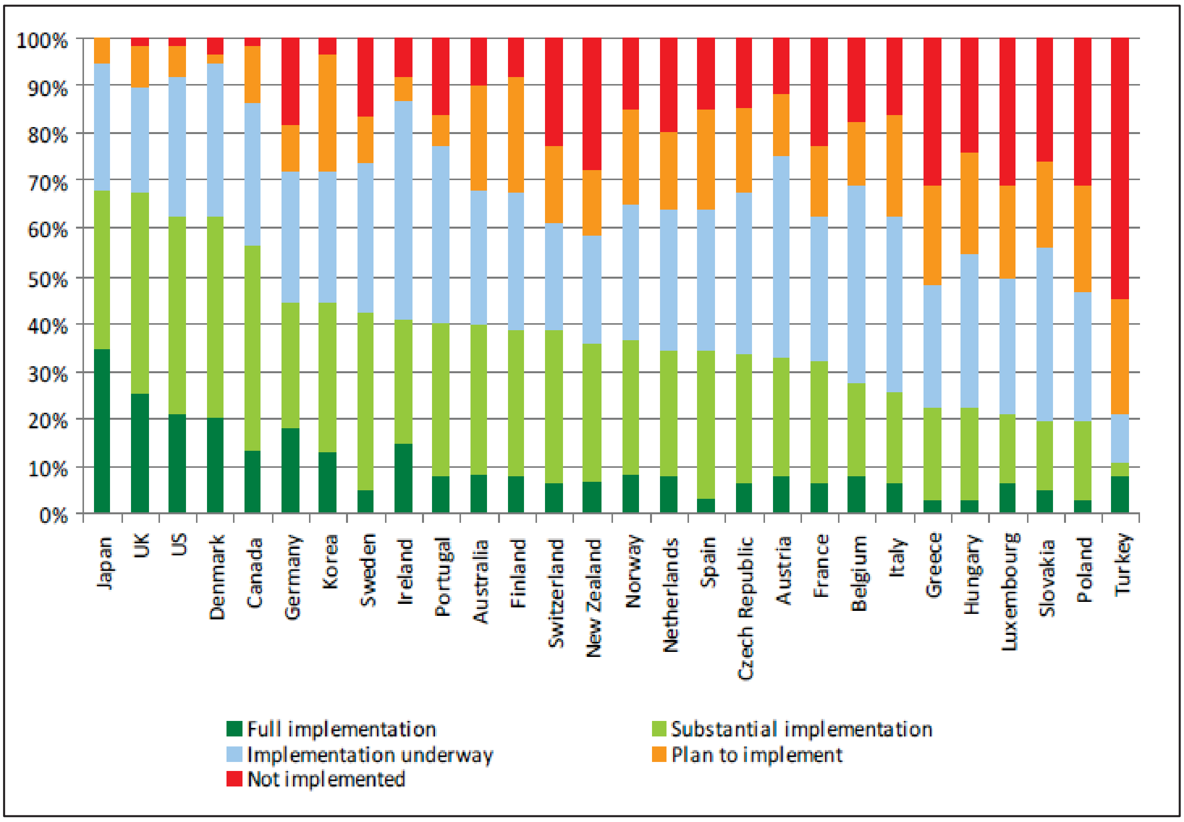


Figure 6-5 Implementation of IEA recommendations – country comparison, 2011

(IEA, 2011)

6.3 The Policy Palette

As discussed in Chapter 5, there have been numerous studies of the barriers to DM and decentralised energy. As shown in Figure 5-6, this thesis applies the barriers spectrum to classify institutional barriers into seven broad areas:

1. regulatory failure
2. inefficient pricing
3. the payback gap
4. split incentives
5. lack of information
6. cultural barriers
7. confusion.

The primary purpose of analysing institutional barriers to DE is, of course, to develop effective strategies to address these barriers. As stated by Sanstad and Howarth (1994, p. 815), 'the important question for policy purposes is whether there are possible interventions or alternative institutional arrangements by means of which such costs can be overcome when they are present'.

As noted in Section 5.6, the effect of institutional barriers is to create additional costs in adopting DE (assuming they do not entirely block DE). These additional 'transaction costs' ultimately have to be borne by the purchaser of the DE technology. This means that the *effective demand* for DE falls short of the total potential demand or *underlying demand*, so the total adoption of DE is reduced. This effect was illustrated in Figure 5-3 and is reproduced here in Figure 6-6.

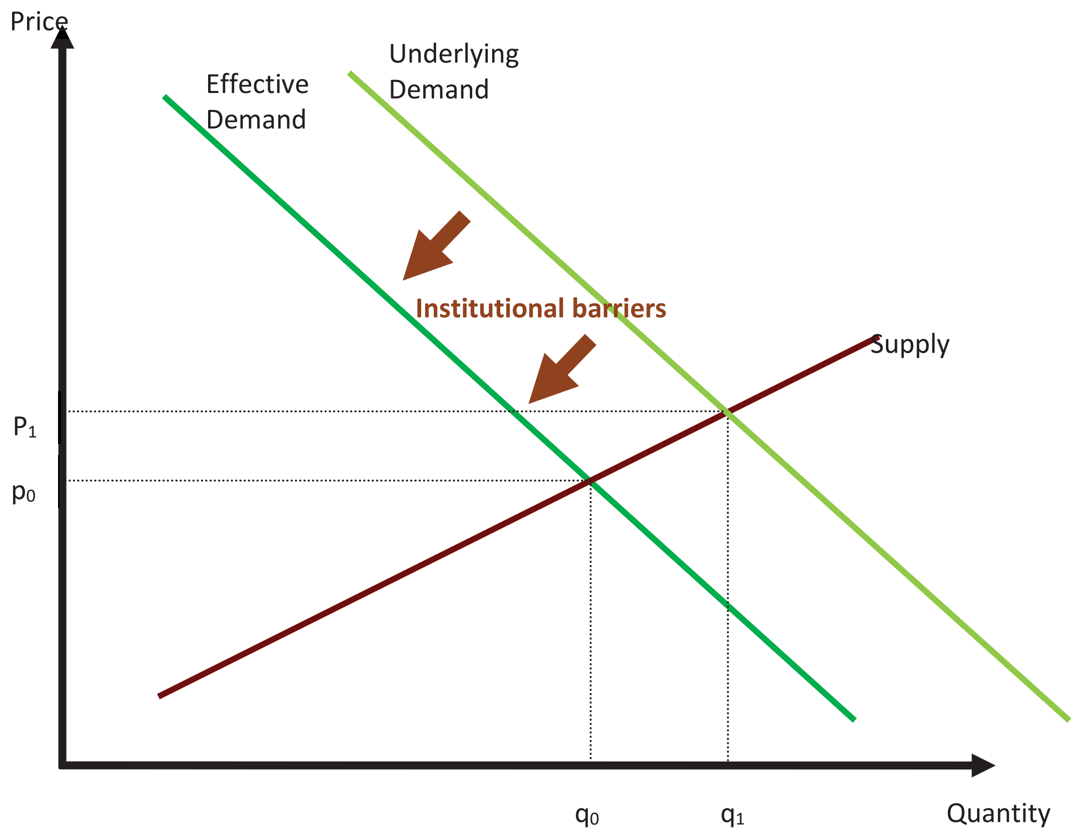


Figure 6-6 Effect of institutional barriers on the demand for DE

Wherever policy tools can counteract these barriers, the transaction costs are reduced and the effective demand for DM is restored to closer to the underlying demand. Policy tools can increase the demand for DE in three ways, as illustrated in Figure 6-7:

1. by 'pushing' the demand higher and to the right through regulation to mandate higher use of DE technologies (or conversely, or lower use of centralised energy substitutes);

2. by ‘pulling’ the demand higher and to the right by offering incentives or subsidies for DE

3. by ‘lifting’ demand by reducing transaction costs caused by institutional barriers so that the effective demand approaches underlying demand. (This is represented below as a lift of the demand curve.)

There is a fourth way to increase demand. This is via technological change to lower the supply curve. Policies to support research and development can have this effect. However, as such policies are aimed at reducing technical barriers rather than institutional barriers, these policies are beyond the focus of this thesis.

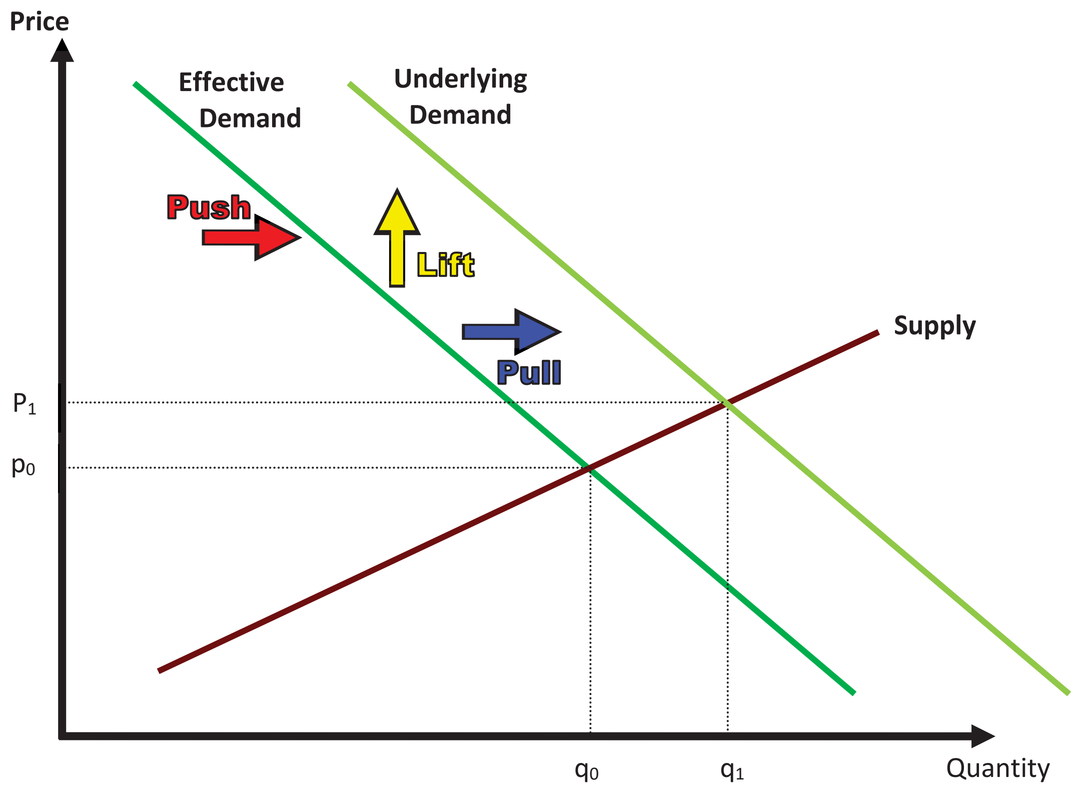


Figure 6-7 Moving the market (demand and supply)

The same effects are illustrated in a simplified form in Figure 6-8. Mandatory instruments such as regulations ‘push’ the market, incentives such as rebates ‘pull’ the market, and reducing transaction costs by, for example, making better information available ‘lifts’ the market.

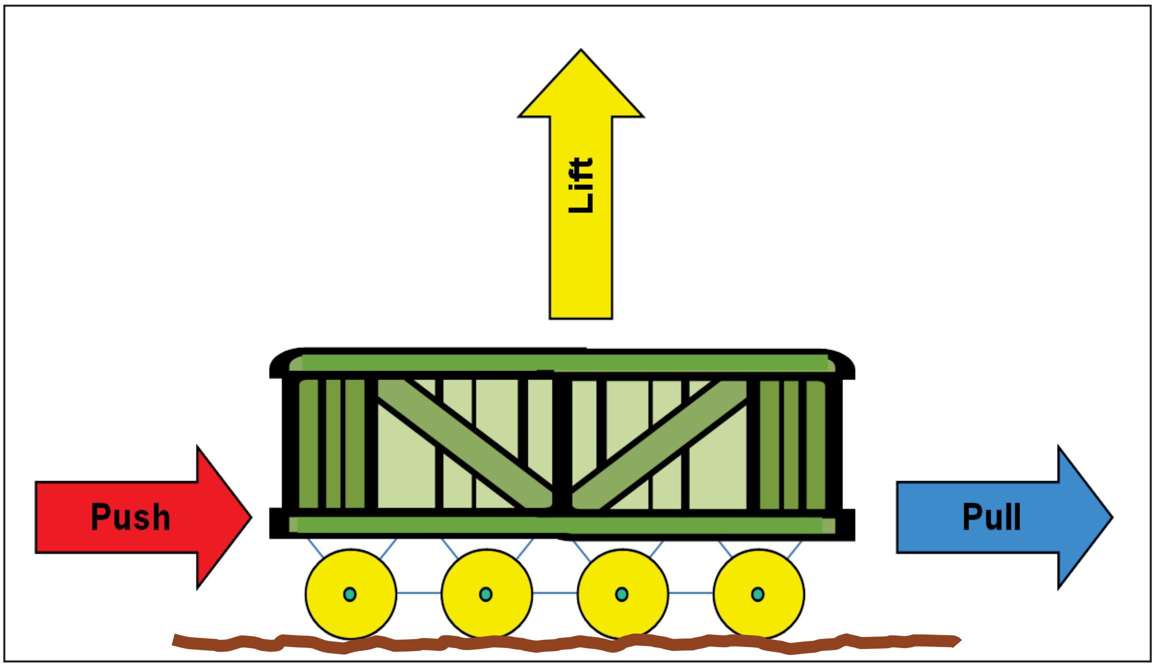


Figure 6-8 Moving the market (Push, Pull, Lift)

The categories of available policy tools for moving the market are illustrated in the 'Policy Palette' presented in Figure 6-9. The primary categories of policy tools include: **regulation, incentives** and **information**, complemented by secondary categories of **targets, facilitation** and **pricing**. The seventh category is effective **coordination**. This is not intended to imply that secondary categories are less important than primary categories are, but rather that secondary categories are less clearly delineated.

This framework offers a structure that can be further developed for classifying and coordinating policy tools to support DE and DM.

Figure 6-9 The 'PERFICT' Policy Palette: policy tools to move the market

As indicated in Figure 6-9, the seven categories of policy tools create a colour palette with which to address the institutional barriers described in Section 5.6 The use of these policy tools is likely to be most effective when a combination of tools is deployed from across the palette. For example, the use of regulation in isolation can invite public or market resistance, while incentives alone are unlikely to lead to long-term change, and information alone will have limited impact. Similarly, without some coordination, there is a high risk of duplication, waste or unintended consequences.

As with the barriers spectrum classification system introduced in Section 5.6, the Policy Palette aims to use categories that are 'mutually exclusive and collectively exhaustive'. In practice, however, not all policy tools fit neatly into a single category). The following classification, using seven categories of policy tools to develop DM, is proposed:

1. **R**egulation – establishing laws and rules to require desirable behaviour and penalise undesirable behaviour
2. **P**rice Reform – more accurately reflecting costs (including environmental costs) in energy prices
3. Incentives (or '**E**nticement') – offering financial and other rewards for particular behaviour

4. **F**acilitation – making it easier for customers and suppliers to capture available benefits
5. **I**nformation – providing accessible, timely, relevant information
6. **T**argets – establishing specific objectives and measuring performance against them
7. **C**oordination – ensuring that policy tools are applied in a coherent way.

Taking the first letter of each of category creates a useful mnemonic: 'PERFICT'.

These categories are illustrated in Figure 6-9 and discussed further below.

These seven categories of policy tools provide, as indicated, a palette with which to address the institutional barriers described above. One of the key implications is that their use is most effective when the full range of policy tools is deployed – that is, when policy tools from the whole palette are included. For example, in isolation the use of regulation could elicit a backlash and/or reduced effectiveness due to a lack of information. Equally, the use of incentives and information alone may result in a weak uptake, or 'cream-skimming'. Above all, it is important to reduce the risk of fragmentation by the overall coordination of the implementation of the range of policy tools.

6.3.1 Market support vs. market transformation

Offering market support through subsidies and other direct incentives can encourage the adoption of DE and DM. However, if such support is not strategically targeted at reducing or removing specific institutional barriers, then it may have little long-term effect, and may even add additional barriers and inefficiencies of its own. Market transformation has been defined as 'The reduction in market barriers resulting from market intervention, as evidenced by a set of market effects, that lasts after the intervention has been withdrawn, reduced, or changed.' (International Energy Agency, 1999, p. 5). Moreover, the potential gains from DM will only be realised if the costs associated with adopting these policy tools is less than the value of the efficiency gains from applying the DM.

The ultimate test of market transformation is whether the policy measures lead to permanent and self-sustaining change.

6.4 Applying the Policy Palette to electricity demand management in Australia

Policy tools are essential in developing DE and DM as they provide a means of unlocking the potential benefits of DE by addressing the institutional barriers discussed in Chapter 5. The success of policy tools is ultimately measured by the extent of greater adoption of DE, lower costs and lower carbon emissions.

The remainder of this chapter applies the Policy Palette framework by examining a range of policy tools for developing DE and DM in Australia. The 20 policy tools presented below are classified and mapped on the 'Policy Palette' in Figure 6-10. Similar approaches to categorising policy tools to support DM has been previously applied in various ways by Cowart et al. (2001 and 2003) and Rosenow et al. (2017).

As no single policy tool is a panacea, the suite of policy tools implemented must operate in harmony, with minimal duplication and effective targeting of identified institutional barriers. Therefore, it is useful to map the tools onto the 'policy palette' to visualise the balance across different policy tool categories and to enable effective planning and coordination of policy tools, as illustrated in Figure 6-10.

This selection was developed through an initial long list of policy tools derived from a literature search, the author's own personal experience in electricity policy reform and consultation with research colleagues. From this long list, a draft list of 20 highest-priority policy tools was developed. This list was published in a working paper for the Intelligent Grid research program (Dunstan et al., 2011b). This list and the associated working paper were workshopped with a wide range of stakeholders at a series of Intelligent Grid stakeholder forums held across Australia. In particular, in November 2009, a stakeholder forum was held in Sydney focusing on policy tools to develop DE. As part of this forum, separate workshop sessions were held on energy efficiency, distributed generation and peak load management. These forums helped to inform the development of the policy tools presented below.

A revised list of the policy tools was included in the Australian Distributed Energy Roadmap (Dunstan et al. 2011f), as part of the CSIRO Intelligent Grid research program. The revised version of the policy list and Policy Palette is shown in Figure 6-10. This figure illustrates a diverse range of tools across the range of primary and secondary policy categories. This representation of a broad range of key reforms to address the range of institutional barriers discussed in Chapter 5 and summarised in Table 5-3.

Sections 6.5 to 6.11, apply the policy palette by presenting, analysing and classifying the 20 priority policy tools in each of the policy categories. This discussion broadly reflects the institutional context that prevailed at the time the research was undertaken between 2009 and 2011. There have been some important reforms and evolution of the institutional context since this time. Chapter 9 revisits this analysis in the light of these changes, including highlighting some of the important reforms to which the research undertaken for this thesis has contributed.

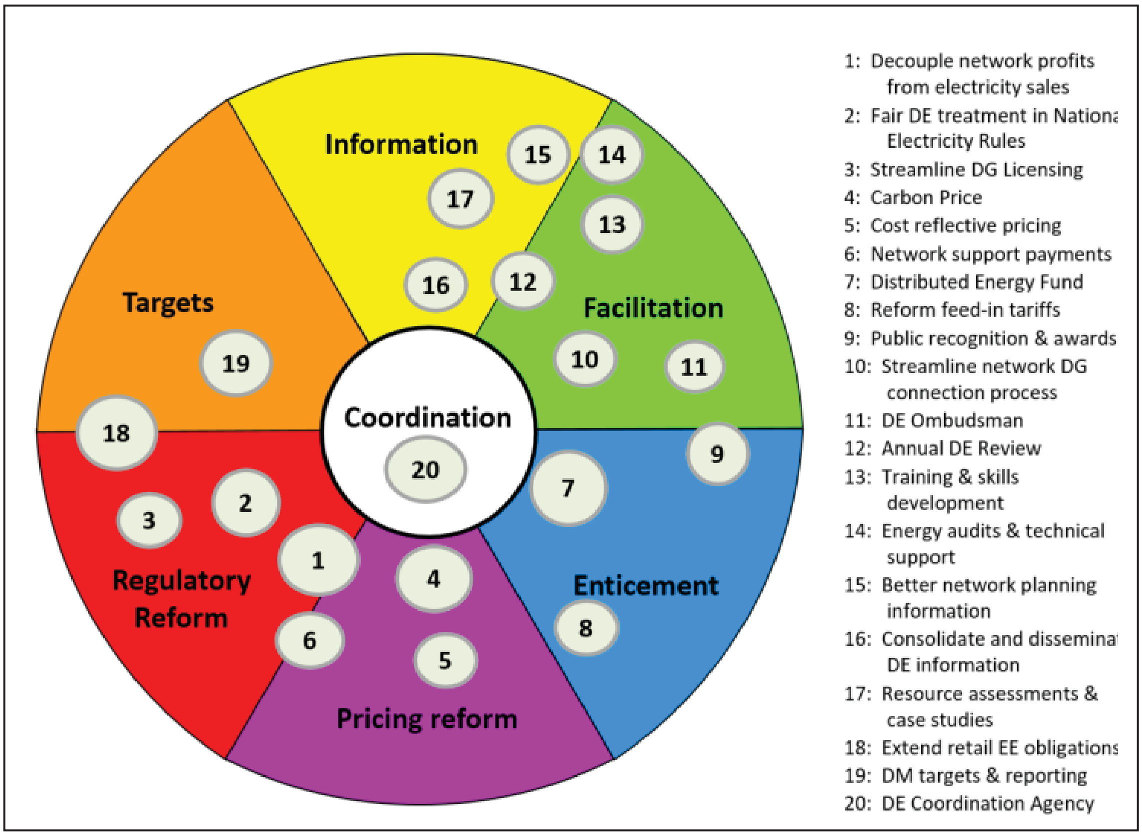


Figure 6-10 Mapping policy tools for developing DE and DM onto the 'policy palette'

(Dunstan et al., 2011, p. 44; Numbers adjusted to match numbering of policy tools below.)

The colours of the section headings below match the colours for each corresponding category in Figure 6-10 above.

6.5 Regulation and regulatory reform

As will be discussed at length in Sections 8.1.1 and 8.1.2, major liberalisation of the Australian electricity industry began in 1991 with reforms to create a competitive electricity market (Industry Commission, 1991). In principle, this reform included strong support for DM:

> Demand management and renewable energy options are intended to have equal opportunity alongside conventional supply side options to satisfy future requirements. Indeed, such options have advantages in meeting short lead-time requirements (National Grid Management Council, 1992, p. iii).

However, as it developed and formally commenced in 1998, the NEM did not have effective provisions providing equal opportunities for DM. While there have been subsequent attempts to encourage DM in the NEM (IPART 2002; COAG Independent Energy Review Panel 2002; AEMO 2009a; AEMC 2012; Finkel 2017) this has yet to lead to a vibrant DM market.

These liberalisation reforms changed the delivery of electricity from a public service to a commercial activity. This also involved establishing multiple government bodies and organisations with regulatory responsibilities. The COAG Energy Council aims to create a common direction of reform across Australian energy markets by initiating, developing and monitoring the implementation of high-level policy. The Australian Energy Market Commission is responsible for the rule-making process and making determinations on proposed rules. The Australian Energy Regulator monitors and enforces the laws and rules governing the NEM, while the Australian Energy Market Operator is the single operator of the NEM.

Today, the energy market is highly regulated. Forms of regulation include:

- technical and safety standards
- economic regulation of monopoly network businesses
- environmental standards, (including local air and water pollution, dust and noise, and from time to time limiting greenhouse gas emissions)
- efficiency standards (minimum energy performance standards – MEPS) on appliances, equipment and buildings
- information disclosure (including emissions from power stations and some building and appliance efficiency performance).

Regulation is generally enacted for sound policy reasons. However, as noted in Chapter 5, regulation can often create undesirable side effects. Such regulatory failure can be a key barrier to DM development.

As will be discussed in Section 8.5, network businesses are a particular focus of this analysis, not only in the area of regulatory reform, but also for other policy tools such as targets and improved information provision. Many existing clean energy obligations in the National Electricity Market focus on electricity retailers as the delivery agents. However, electricity network businesses are key agents in developing DM for a range of reasons including that they:

- have direct control over network planning and connection of distributed generators
- are responsible for large expenditure and have large asset bases
- are the potential beneficiaries of efforts to avoid infrastructure spending through managing peak electricity demand.

Note also that the focus of the regulatory reforms proposed below is on tools that could be implemented in the near term to enhance demand management uptake. There are other regulatory reforms likely to be effective in the longer term, such as addressing the issue of peak demand growth through the introduction of peak load shedding criteria within the Australian Building Code, or further appliance efficiency measures through Minimum Energy Performance Standards (MEPS) or other means.

6.5.1 Tool 1: Decoupling network profits from electricity sales.

Description:

Reform economic regulation, which has traditionally penalised network businesses that reduce their electricity sales volume by supporting DM, by adopting a ‘revenue cap’ form of regulation. Under a revenue cap, if a network successfully encourages DE, resulting in an electricity sales reduction, the network business can increase prices without increasing customers’ bills. Prior to 2014, revenue caps applied to distribution network service providers (DNSPs) in Queensland, Western Australia and Tasmania from 2012 (as well as transmission network businesses throughout Australia) but not in NSW, Victoria or South Australia.

Responsibility:

The Australian Energy Regulator (AER) assumed responsibility for the economic regulation of the distribution networks in the ACT and all states and territories except WA and NT in 2008 (AER 2009b, p. 315). Prior to this, due to different regulatory histories, the characteristics of economic regulation of networks varied from state to state.

Why is this needed?

One key regulatory barrier is an unintended result of regulation to limit the market power of monopoly electricity suppliers. In NSW, Victoria and South Australia, electricity distribution network businesses (or 'electricity distribution network service providers' – DNSPs) were, until recently, subject to economic regulation in the form of a maximum average price they could charge. Since network costs are mainly driven by capital costs, which in turn are linked to peak demand, a DNSP's cost structure is not strongly influenced by the volume of electricity flowing through its wires.

As noted in Section 5.6.5, since revenue equates to price multiplied by sales volume, a maximum price cap means that total revenue is directly related to the volume of electricity delivered. On the other hand, total cost is generally not related to sales volume except for sales at the time of peak demand. Since profit is total revenue minus total cost, this means that the profitability of the network business is closely tied to the total sales volume. This means that, under price cap regulation, distributed generation or energy efficiency, which reduce network sales volumes, are a threat to the profitability of the network business.

This relationship has not always been well accepted in Australia. For example, the AEMC Demand-Side Participation Review (AEMC, 2009a) implied that network businesses operating under a price cap, will act to procure load reductions via DM when it is more profitable than to serve load:

> Networks businesses under a price cap will find it profitable to purchase DSP [DM] in situations where that purchase is also efficient from the perspective of society… Price cap regulation creates private incentives for network businesses to buy DSP that are consistent with efficient levels of DSP. Revenue cap regulation has weaker incentives, but is unlikely to represent a significant barrier to efficient levels of DSP.

However, the AEMC did not cite empirical evidence of network businesses investing in DM where this reduces sales volume and they do not acknowledge that market failures exist, as demonstrated by the low levels of demand-side participation in the NEM.

Precedent:

At the time of this AEMC review, the AER had already decoupled revenue from sales in Queensland. In NSW, the D-Factor mechanism was introduced to address this issue. Yet while in principle the D-Factor effectively addressed this regulatory anomaly, in practice the uptake of DM through the D-Factor mechanism by DNSPs was limited. This illustrates the principle that the barriers to DM are complex and effective solutions require a suite of policy tools. For further discussion of the D-Factor, its effectiveness and limitations see Dunstan et al. (2008).

6.5.2 Tool 2: Fair treatment of DM in the National Electricity Rules

Description:

Adapt and enforce current least cost requirements and amend the National Electricity Rules (NER) to better facilitate DNSPs in implementing DM measures wherever they are cheaper than network augmentation.

Responsibility:

The Australian Energy Market Commission (AEMC) is responsible for managing changes to the National Electricity Rules, which can be proposed by any party. The state and Commonwealth energy ministers are responsible for changes to the National Electricity Law, via the COAG Energy Council.

Why is this needed?

The objective of National Electricity Rules requires the electricity market to be operated in the 'long-term interests of consumers', and deliberately excludes consideration of environmental concerns. This approach has created some confusion as to how the long-term impacts of climate change on consumers should be considered. For example, support for DM measures that would reduce the expected future financial cost of carbon pollution or carbon permits has generally not been considered in regulatory decisions.

Currently, distribution network businesses are required to consider demand management, or ‘non-network alternatives’, where it would be cost-effective in order to satisfy the ‘regulatory test’ (Section 5.6.2(g) of the NER), for new network augmentation with a total capital cost of over $5 million.[35] Anecdotal evidence suggests that traditional approaches to network development are not adequately challenged by the structure of the regulatory test. Factors such as the relatively short lead times prior to instigating network options do not favour DM.

Even though the AER is required by clauses 6.5.6(e)(10) and 6.5.7(e)(10) of NER to consider ‘the extent the Distribution Network Service Provider has considered, and made provision for, efficient non-network alternatives’, it is evident that it may not be effectively doing so. For example, in conducting its review of capital and operating expenditure for the AER’s first distribution network price determination, the 2009-14 NSW and ACT regulatory determinations, the AER’s consultants stated that,

> The following matters ***were excluded*** from consideration in our work or were not undertaken: ... ***consideration of the possible effects of*** the following factors that can only be conjectured;
>
> - possible adjustments in capex stemming from the application of ***demand management*** policies other than those already reflected in the DNSPs’ estimates (Wilson Cook & Co, 2008, p. 16, emphasis added).

The consequence of the current regulatory structure is that rigorous least cost principles to treat demand management on a level footing with network augmentation are not effectively tested and enforced. Additionally, the National Electricity Rules do not explicitly state that DM should be implemented wherever it is a less costly option than augmenting supply infrastructure.

Changes to the National Electricity Rules and National Energy Law to level the playing field for DM would include:

[35] The details of the regulatory test including the capital expenditure threshold are published by the AER at http://www.aer.gov.au/content/index.phtml/itemId/709346

a) Adding explicit considerations for DE into the NER and NEL. For example, Section 6.2.5 (c) of the NER describes AER's required considerations when deciding on a control mechanism for standard control services. A consideration that should be added is:

> …the need to ensure that the Distribution Network Service Provider is not financially disadvantaged as a consequence of actions it takes to encourage or support improved energy efficiency, peak load management or distributed generation that benefits consumers.

b) Amendment of clause 5.6.2(f) of the NER to expand the level of market engagement in the determination of feasible DM options, particularly for smaller-scale augmentations. Currently no consultation is required for augmentations of below $5 million, and only an internal DM screening occurs at which point DM is commonly qualitatively discounted with little analysis or justification.[36] DM should be formally considered in the context of much lower-cost projects and also not only for augmentation projects.

c) Require NSPs to *implement* DM wherever it is a lower cost option, and meet the reliability tests before network augmentation.

d) Improve the AER's enforcement of required consideration of DM by NSPs by setting mandatory DM reporting requirements. (This also relates to Tool #12 (Annual DE Review), Tool #15 (Better Network Planning Information) and Tool #19 (Targets and Reporting)).

e) Amend Section 5.5 (h) of the Rules to allow *full* pass through of avoided transmission use of system (TUOS) charges to distributed generators, as opposed to solely the 'locational component', which tends to equate to a less

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[36] The following provides an example of a common response discounting DM options at the screening test phase: *"The demand management requirement is large in total MVA, and moderately significant in relation to total demand in the area. The deferral value is low. There is little time to identify and develop DM options before the investment decision must be made. On balance it is considered very unlikely that sufficient cost effective demand reductions could be identified to enable a smaller capacity and lower cost design at the new Adamstown zone substation."* Energy Australia's Adamstown DM Screening Test, circa 2009, <http://www.energyaustralia.com.au/Common/Network-Supply-and-Services/Demand-Management/~/media/Files/Network/Demand%20Management/Demand%20Management%202/Progress%20tracking/Screening%20tests/DMST_Adamstown_zone.ashx>, p.4.

than half of total TUOS. This amendment would need to be implemented with due consideration to Tool #6 (Default Network Support Payment).

f) Explicitly encourage network businesses to invest in demand management options up to, say, five years prior to the corresponding trigger point for network augmentation (whilst accounting for additional cost associated with early investment in DM). Whilst this is currently *allowed* in that there is no regulatory barrier to NSPs investing earlier in DM, it seldom occurs. This would allow NSPs to test the effectiveness of DM, and progressively build a larger base of DM, before they are under pressure of potential reliability constraints.

g) Requiring standardised reporting of network expenditure and outcomes related to DM activities. Note that as of December 2010, AER undertook to address this through a Regulatory Information Order. However, this has yet to be comprehensively and consistently implemented.

Precedent:

The American Council for an Energy Efficient Economy (ACEEE) State Energy Efficiency Resource Standard (2010) reports that six US states are required to purchase any cost-effective energy efficiency resources, sometimes specifically as an alternative to new supply options.

6.5.3 Tool 3: Streamline licensing and connection for distributed generation

Description:

Streamline the complex and costly licensing requirements and procedures required for distributed generators to produce and supply electricity to the grid. This involves the review of generation, distribution and retail licensing requirements across the relevant types and scales of DG operators. Streamlining DG licensing (a regulatory reform) is closely related to Tool #10 (Streamlining network connection negotiation processes), which is listed separately as a complementary facilitation tool.

Responsibility:

This is a complex policy area involving contributions from different areas of regulatory responsibility:

- Chapter 5 of the NER covers connection of registered generation to transmission and distribution systems.
- The AEMC oversees the NER and manages the NER 'rule change' process, which can be proposed by any person or body.
- The AEMO manages the operation of the NEM, including development and amendment of *procedures* governing market participants, including generator registration. Again, procedural changes can be proposed by any person or body.
- At the instruction of the COAG Energy Council, the AEMC and AEMO also undertake or oversee reviews of energy market issues to determine reform priorities. Several of these reviews have related to DM in recent years.
- The AER is the economic and market/rules compliance regulator, and it determines what DNSPs and TNSPs can charge for their services, oversees market participant compliance with the NER, and can issue distribution licensing exemptions to embedded generators in certain cases.

Why is this needed?

Generator licensing and connection procedures: Under the NER, any party who owns, controls or operates a generating system connected to a transmission or distribution network must register as a generator with AEMO. Exemptions to the registration process and associated fees can be obtained by generators under 5MW, or (through special application) by generators below 30MW that export less than 20GWh into the grid in a year (AEMO, 2009b). This means that while small-scale (< 5MW) renewable and other DG options are generally not required to register, larger-scale DG options such as co- and tri-generation projects can be required to pay registration and participant fees to AEMO. While there is no actual impediment to the ability of any willing participant to register as a generator, annual fees and processes can pose significant cost and administrative burdens and act as a barrier to registration as a market generator.

In November 2009, the Ministerial Council on Energy's Network Policy Working Group (NPWG) released draft legislation establishing a national connections framework for electricity distribution, which aims to streamline the connections process for non-registered embedded generation (MCE, 2009). This provides an important opportunity to ensure that these barriers are overcome by setting out the terms and conditions for access, timelines and negotiation process steps. However, it does not go far enough to adequately streamline the connection process.

Retail licensing: Standardisation of retail licensing conditions across the NEM involved the adoption of the National Electricity Retail Law and Rules as part of the National Energy Customer Framework package. This legislation, the National Energy Retail Law (South Australia) Bill 2010 (which includes the National Energy Retail Law) covers the relationships between customers, retailers and distributors for both gas and electricity in a single package.

Given the above issues, elements of this broad regulatory reform to streamline licensing requirements for DG may include the following components:

- Simplify and standardise contractual licensing arrangements: Relaxing generator rules, such as through the creation of a category for small non-market generators exporting less than 30MW. Such a generator could sell to any retailer at the connection point.
- Standardise payments and costs: Cost allocation rules should make clear which party is responsible for network connection costs, e.g. costs triggered by fault currents that may require network augmentation. In addition to the AEMC technical standards review, DGs should only have to pay upgrade costs proportional to their total demand in the local area, specifically in cases where fault currents are already at their limit.

This tool also links with Tool #11, a DM Ombudsman, in that the Ombudsman could facilitate this process by providing expert information, as well as a low cost review and inspection of the connection process.

6.6 Pricing Reform (including external environmental costs)

6.6.1 Tool 4: Impose a price or cap on carbon pollution

Description:

Re-introduce an effective market price (or binding cap) on carbon emissions for electricity.

Responsibility:

The Commonwealth Government is the most appropriate body to apply such a broad policy measure as this, as it did between 2012 and 2014. However, while the previous policy was well administered and effective, it had serious design flaws, was poorly communicated and was very contentious. There are currently efforts to reinstitute a similar mechanism via the proposed National Energy Guarantee (Australian Government, 2017). In the absence of action at a Commonwealth level, it is quite possible for state and territory governments to impose a price on greenhouse gas emissions as the NSW and ACT Governments did through the Greenhouse Gas Abatement Scheme between 2003 and 2012 (IPART, 2013, p. 1).

Why is this needed?

The most prominent external cost of electricity supply is the cost of climate change caused by the burning of fossil fuels to generate electricity. This means that the average price of electricity is set below its true cost of supply, leading to excessive consumption of centralised coal-fired electricity supply and reducing the uptake of lower carbon intensity decentralised energy options.

The simplest mechanism to redress this barrier and ensure energy suppliers sufficiently factor in emission costs, is to put a price on carbon through either a carbon tax, as was the case for the Commonwealth Government's former carbon pricing mechanism, a carbon emissions trading scheme as in the NSW Greenhouse Gas Abatement Scheme (GGAS), or cap on emissions as for the proposed National Energy Guarantee.

Precedents:

Australian Carbon Price (2012-2014)

The Australian Government's Clean Energy Regulator describes the carbon pricing mechanism that operated in Australia from July 2012 to June 2014 as:

> …an emissions trading scheme that put a price on Australia's carbon pollution. It was introduced by the Clean Energy Act 2011 and related legislation and applied to Australia's biggest carbon emitters (called liable entities).
>
> Under the mechanism, liable entities had to pay a price for the carbon emissions they produced. This covered approximately 60 per cent of Australia's carbon emissions including from electricity generation, stationary energy, landfills, wastewater, industrial processes and fugitive emissions (Clean Energy Regulator, 2015).

NSW Greenhouse Gas Abatement Scheme

The NSW Greenhouse Gas Abatement Scheme (GGAS), 2003-2012, established annual state-wide GHG benchmarks, at 7.27 t CO_2e per capita from 2007 to 2012, representing a per capita reduction of 5% in NSW electricity sector GHG emissions below 1990 levels. The target was set to be challenging, yet achievable and to establish a reasonable price signal (DEUS, 2006). According to the NSW Government, the GGAS met the Government's objectives in establishing the Scheme, including creating financial viability for lower emission generators and abatement projects; providing market certainty via a price signal for GHG abatement; and minimising the cost of abatement in comparison to other regulatory barriers (DEUS). The GGAS scheme was abolished in 2012, following the introduction of the national carbon price (IPART, 2013, p. 1).

6.6.2 Tool 5: More cost-reflective network pricing

Description:

Introduce incentives for time-of-use pricing and deploy smart meters to residential and business customers.

Responsibility:

DNSPs are primarily responsible for setting their network prices, subject to overall limits imposed by their economic regulator (generally the AER). However, the AER and government departments can do much to provide incentives and support greater and faster application of time of use pricing.

Why is this needed?

While less obvious than excluded external costs, pricing structures can be an even greater barrier to DE than the exclusion of external costs, e.g. carbon pricing. Although interval meters and time-of-use tariffs are becoming more common, most electricity consumers in Australia, particularly smaller consumers, still pay a flat electricity tariff. That is, they pay the same electricity price all day, every day throughout the year.[37] This flat tariff is in contrast to the wide variations in the cost of providing electricity both in the wholesale (generation) price and reflecting the cost of providing peak capacity in networks.

Retailers face a strong price signal when demand peaks, but the price variability is usually lost when a flat tariff is offered to a customer (AEMO, 2010a). These current charges are too imprecise to signal costs with sufficient accuracy to attain all the opportunities for efficient demand side participation. The limited extent of interval metering technology, outside Victoria, considerably constrains the ability to charge cost-reflective pricing (AEMC, 2009a).

A flat price structure creates a bias against DE options that would be well suited to respond to these cost fluctuations. While flat tariffs are sometimes defended as protecting vulnerable consumers, the effect is often to impose avoidable costs on all consumers to pay for large investment in centralised generation and networks to meet occasional peak demand.

Given the pre-eminence of peak demand growth in driving network and generation investment decisions, in the long term it is crucial that electricity prices are fundamentally reformed. This relates both to energy (generation) and to network prices which combine to produce cost-reflective retail prices.

[37] The main exception to this rule is off-peak electric water heating.

In recent years, there have been numerous real-time metering and time-of-use pricing trials by Australian utilities. In 2006, COAG agreed to improve price signals for energy consumers and investors by committing to the progressive national roll out of 'smart' electricity meters. Their cost benefit analysis showed substantial benefits over costs nationwide but with varying levels across jurisdictions. The deployment of time-of-use and 'smart' meters and time-of-use pricing has generally been slow and has focused on relatively weak time-of-use signals. However, public resistance to smart meters was exacerbated by a very poorly managed rollout in Victoria.

Studies show that a major peak demand reduction can be achieved from the introduction of cost-reflective pricing and specifically, critical peak pricing (NERA 2008). Regulators and governments should support instruments to hasten a well-planned and managed rollout of time-of-use pricing and in particular 'dynamic peak pricing' which involves much higher electricity prices for the infrequent periods of the very highest power demand. Such instruments include:

- Expedite the regulated recovery of costs for smart meter rollout as per the COAG's 2007 directive (MCE 2008b), wherever net benefits to customers are demonstrated, particularly in relation to load management and reduced demand.
- A partnership between government, regulators and network businesses, to support network business rollout of smarter meters and cost-reflective pricing, with appropriate hardware and software (i.e. load control technologies, in-home displays, educational programs).
- Well designed and executed public education on the reasoning for and benefits of smart metering and time of use tariffs. To limit political resistance to going beyond current mild time of use tariffs to critical peak pricing models it likely to be necessary to make such models voluntary for consumers and combined with incentives.
- Conduct assessments and promote the benefits of cost-reflective network pricing by both transmission and distribution network businesses. This could be performed by a coordinating body such as that recommended in Tool #20 (Agency to Coordinate DM Development).
- Monitor and publicly report on progress in the uptake of time-of-use pricing across Australia, particularly in relation to reductions in energy consumption, peak demand and the use of distributed generation.

- Publicly recognise best practice performance.

When designing such a program it is important to consider the social equity issues that may arise with cost-reflecting pricing, such as those associated with vulnerable consumer groups unable to shift demand to off-peak times, and how to minimize these issues. For this reason the effective expansion of smart meters should closely involve effective engagement with public interest advocacy organisations.

Precedents:

- The Smart Grid City in Boulder Colorado identified more than 70 value drivers to help build the business case for time of use pricing and smart grid technologies (DEWHA 2009).
- A partnership between the US Government and utilities included earmarking $3.4 billion for smart grid investment grants (DEWHA, 2009).

6.6.3 Tool 6: Default network support payment for distributed generators

Description:

Establish a standard or default network support payment, to be paid by the network business to distributed generators (DGs) exporting power to the main grid. Ensure that network businesses are not disadvantaged in providing such payments.

Responsibility:

Network businesses have the key responsibility for assessing the value of avoided network costs that can be used to fund network support payments. The AER could make provision for default network support payments in its network revenue regulation decision and the AEMC could make a rule to require the establishment of default network support payments.

Why is this needed?

Most distributed generators are currently designed and sized to offset electricity purchases of the owner or host, thus avoiding the full retail cost of electricity supply, including network charges. However, the export of power from such facilities to the grid typically only attracts the wholesale price, which is 40 to 60% lower than the retail cost. The wholesale price is much lower than the retail price, primarily because it excludes the network charges.

Distributed generators can currently negotiate with DNSPs to be paid a 'network support payment' for exported energy. This recognises that whenever a distributed generator exports energy to the grid and thereby reduces peak demand on the network, it is reducing the need for network infrastructure to deliver power from distant centralised power stations.

Currently, distributed generators are seldom rewarded for this (often significant) value of avoided network infrastructure. Under Clauses 5.5 (h) and (i) of the National Electricity Rules (ver. 30), the pass-through of avoided TUOS costs from DNSPs to distributed generators is mandatory, which is reflected in Energy Australia's standard generator connection contract (ver. 2, April 2009). However, generally the value of this TUOS pass through is only the volumetric component which is around one third of the average TUOS charges. Avoided Distribution Use of Service (DUOS) costs do not fall within the National Electricity Rules and there is no explicit wording around this issue contained in the AER's Final Distribution Determination for the 2009–10 to 2013–14 regulatory period (28 April 2009). Consequently, DNSPs seldom pass through to embedded generators significant avoided TUOS and DUOS network costs.

It is often suggested that the value of distribution generation to the network is negligible because there is a significant risk that due to planned maintenance or unplanned faults, the distributed generator will not be generating at the time of peak demand. However, the unexpected unavailability of energy exported from a distributed generator is comparable to an unexpected increase in customer demand of the same amount. Responding to unpredictable spikes in customer load is a routine matter for network businesses, so dealing with comparable dips in export of a power from distributed generators should also be manageable. DNSP concerns about distributed generator risks can, as with the management of customer demand, be managed through pricing incentives. Structuring the level of network support payments to reflect the different value of network support at different times can be an effective means of sharing risk between the DNSP and the distributed generator.

The focus of this negotiation process could be the setting of a 'default network support payment'. While the DNSP and distributed generator should still be free to negotiate alternative arrangements by mutual consent, a default network support payment would serve to both strengthen the negotiating position of distributed generators and streamline the negotiation process.

The default network support payment could be based on the principle that energy exports receive a network support payment equal to the actual distribution and transmission network charges prevailing at the time, place and voltage level minus the off-peak network charges for that same place and voltage level. Provided the prevailing network charges were set at efficient levels, this approach would recognise the capacity value of the energy export, without including the value of base network connection costs. It is also essential that default network support payments be set for a reasonable minimum period of time, such as ten years. Network support payments should apply not only to exported power, but also to electricity 'exported' from the facility to other users on the same site, such as in a shopping centre or industrial estate.

Network support payments should be paid by the local DNSP, reflecting the avoided cost of providing network infrastructure. It should be recognised that DNSPs often hold the position that network support payments represent a real cost to their business, but that the avoided network costs do not represent real savings as existing capacity has already been built and must be paid for, and proposed capacity has not yet been built and the revenue to cover such investment has not yet been recovered. While commentators differ in their views on this issue, it is likely to be easier to encourage DNSPs to offer network support payments if there is a specific mechanism for recovery of these costs by the DNSP. A default network support payment would provide a more balanced foundation for negotiation of an appropriate export payment structure and give DG proponents greater confidence to develop projects.

Precedent:

In NSW, the former 'D-Factor' scheme provides a cost recovery mechanism for network support payments (AER 2009a, p. 470). It allowed the DNSP to recover the electricity sales revenue foregone from demand management (DM) activities that it had implemented as well as the direct cost of DM measures themselves up to the value of the avoided network investment. Therefore, DM investments under the D-Factor resulted in reduced capital expenditure on new infrastructure, but no corresponding reduction in revenue for the DNSP. In the context of DE, the reduced sales revenue for the DNSP was recoverable through the D-Factor, while the remainder of the avoided network costs could be recovered by the DNSP and 'passed through' to the project operator in the form of network support payments.

Nearly every US state requires some form of net metering for distributed generation. Net metering requires the DNSP to pay the full retail rate and thereby effectively transfers payment of transmission and distribution costs to the generator. See the Database of State Incentives for Renewables and Efficiency, and specifically their Net-metering Policies Summary Map (North Carolina Clean Energy Technology Center).

6.7 Incentives (Enticement)

Incentive measures are intended to stimulate behaviour change. They are economically beneficial wherever the total benefits of this behaviour change exceed the total cost of providing the incentive. Examples of incentives include:

- cash rebates
- competitive subsidy bidding programs (such as the one applied by the Victorian Demand Management Action Plan in the early 1990s)
- financial support for research and development
- loans and financial guarantees
- expedited planning processes
- public recognition and awards
- prizes
- community rewards, where a whole community is rewarded, for example through the provision of a new local playground as a result of a collective effort to save energy.

In providing incentives, it is crucial to keep in mind the market transformation objective. Incentives generally have a limited lifespan and it is important that the greatest long-term benefit is achieved while they exist. For this reason, incentives are often most effective when combined with other policy tools. Consequently, not all the incentive options discussed below are necessarily desirable or required if complemented with other policy options such as regulatory reform efforts or other instruments.

6.7.1 Tool 7: DM Fund

Description:

Establish a fund specifically to support DM development.

Responsibility:

A DM fund could be raised and administered by governments, or by regulators through electricity retailers and/or DNSPs. For example, in 2008 the AER established a Demand Management Innovation Allowances (DMIA) in NSW, the ACT, Victoria, South Australia and

Queensland to implement innovative non-network alternatives. The DMIA is generally part of a broader Demand Management Incentive Scheme (DMIS) however the DMIS is not intended to be the sole or primary source of recovery of demand management expenditure (AER 2008). The AER reformed the DMIS in 2017, as discussed in Section 8.5.4.

Alternatively, Commonwealth or state/territory governments could establish a fund.

Why is this needed?

Numerous studies, including those cited in chapter 2, have highlighted that there is large cost-effective potential for DM. As discussed in Chapter 5, there are numerous reasons why this cost-effective potential is not adopted. However, one of the most direct ways to encourage adoption of this potential is to fund it directly.

Given the strategic importance of the secure electricity supply, governments have for many decades provided preferential support for electricity utilities and in particular, networks, both in the form of government ownership and investment and via regulation returns on investment and support for monopoly provision of services. This has given regulated monopolies access to finance with much longer long payback periods (of as much as 40 years) than which is available or applied to providers of DM options.

In recognition of these barriers, and to support the development of energy service companies in Australia, a dedicated fund could be established to assist DM development. To ensure widest possible impact, access to the finance should be open to all parties seeking to develop DM options including electricity distributor network businesses. Specifically, the fund should have comprehensive coverage as outlined by the 2002 Demand Management Inquiry undertaken by the NSW Independent Pricing and Regulatory Tribunal (IPART). The Tribunal stated that:

> A Demand Management Fund or Funds should have the objectives of:
>
> - Facilitating sustainable generation projects
> - Implementing energy efficiency and end-user fuel switching programs to supplement the retailer licence conditions
> - Assisting smaller scale, more diffuse energy efficiency programs

- Encouraging energy efficiency initiatives with a wider range of partners, including equipment suppliers, the building industry and local government
- Facilitating programs that tap the synergies between water and energy demand management (IPART, 2002).

A Demand Management Fund was created in NSW as an Energy Savings Fund in 2005 before being subsumed into a wider Climate Change Fund (CCF) and then repurposed to fund an excessively generous solar feed in tariff.

Financial incentives, or subsidies, are often regarded as a ‘second best’ policy instrument as they generally aim to counteract market barriers rather than reduce those barriers. However, incentives can still be very cost-effective. For example, the Energy Savings Fund component of the NSW Climate Change Fund was reported to have achieved 189,376 MWh p.a. of electricity savings at an average cost of $15/MWh (DECC 2008a, p.21). This suggests a very cost-effective outcome when compared to an average retail electricity cost of $80/MWh for business and $150/MWh for residential consumers at that time. The NSW Energy Savings Fund is further discussed in Section 8.1.2.

However, there remains large untapped potential to use incentives to support DM options. As with facilitation, the measurement, evaluation and reporting of the effectiveness of incentives is incomplete and inconsistent. There has been very little use made by energy utilities of incentives for DM when compared to the increasing use of incentives for water saving by Australian water utilities during the drought in the early years of the twenty-first century.

Precedents:

A Demand Management Incentive Scheme has been available for NSW, ACT, Victorian, South Australian and Queensland DNSPs since about 2010. It consisted of two parts: a demand management innovation allowance (DMIA) which provides for the recovery of costs for demand management projects and programs, and an ability for recover forgone revenue by a DNSP as a result of reductions in the quantity of energy sold due to the approved DMIA expenditure (AER 2008). While the existence of these DMIA and DMIS is good in principle, the very modest scale size of these measures was problematic. For example, over the period 2011-15, Victoria’s allowable spend on the DMIA was $10 million over 5 years, which amounted to 0.008% of the value of approved network augmentations, or 0.002% of total network capex

(AER 2010). The recent reform of the DMIS addresses this issue of scale and is due to commence in NSW and Tasmania in 2019 and later in other states.

Twenty states of the USA have public benefit funds for Renewable Energy and Energy Efficiency (Pew Centre, 2010). The funds are collected through a small charge on the bill of every customer or through specified contributions from utilities.

The Scottish Community Renewable Energy Scheme (CARES) provides financial incentives through grant programs and ongoing support of Local Development Officers for community groups developing renewable energy and energy efficiency programs (Community Energy Scotland, 2017). Community stakeholders in DM are often overlooked, however in Europe they have been shown to play an early adoption role for DM technologies.

This program was designed to overcome the specific barriers that community groups have to DM. Specifically, grant funding is available for pre-feasibility and feasibility studies, which communities with minimal cash reserves find difficult to fund. The program also provide some capital grants enabling communities to get a more favourable loan with banks. These programs put stipulations on the funding to ensure maximum carbon reduction and maximum community benefit.

6.7.2 Tool 8: Reform feed-in tariffs

Description:

Reform feed-in tariffs in order to support load management and distributed generation.

Responsibility:

Commonwealth or state/territory governments.

Why is this needed?

A lack of coordinated action on solar feed-in tariffs at the federal level led to a proliferation of different state-level feed-in tariffs that varied widely in value and eligibility criteria. Instruments to improve feed-in tariffs could include:

- Moving from net to gross feed-in tariffs, as applied in some Australian jurisdictions.
- Linking feed in tariffs to dynamic time of use tariffs to encourage load management

- Harmonising tariff value while preserving geographic renewable resource considerations
- Increasing the coverage of feed-in-tariffs to include a range of different DM technologies at different scales

When developing a feed-in tariff policy, it is important to consider the overlap between this and other incentive options (e.g. network support payments and solar credits). For example, in 2010, NSW established a gross feed-in tariff for small scale grid-connected, solar photovoltaic panels and wind turbines, which originally paid 60 cents per kWh. The gross 60 cent per kWh value, particularly when combined with the Commonwealth solar credits scheme providing an effective upfront rebate, resulted in heavy over-subsidisation and hence, dramatically larger than anticipated uptake. This then led to the slashing of the tariff to 20 cents per kWh, replicating the regular boom and bust cycle regularly seen in the Australian solar industry driven through erratic rebate and incentive schemes over the past fifteen years.

Precedent:

Feed-in tariffs have been implemented in over 40 countries and all Australian states and other countries to enable distributed renewable technologies to enter the marketplace.

From the year 2000, the German feed-in tariff program fixed the price of payment for renewable generation on the grid so that renewable technologies had a stable market in which to mature. Beginning in 2002, the tariff rates were decreased at a consistent rate to reward early adopters of the feed-in tariff (Butler & Neuhoff 2005). The scheme is notable for three major differences from other programs:

- It pays for all energy fed into the grid (in contrast to net metering programs in which the supplier can only return electricity drawn from the grid)
- It allows any of a wide range of different generator types and scales to benefit from the feed-in tariff, , thus enabling many different stakeholders from businesses, to community groups, individuals and utilities to participate in the clean energy economy.
- It pays electricity rates based on the generation technology and scale used and geographic region applied, thereby recognising that some renewable technologies are more mature (and cost less) than others.

6.7.3 Tool 9: Public recognition and awards

Description:

Publicly recognise leadership in developing DM options.

Responsibility:

Government energy, environment/climate change or industry departments

Why is this needed?

While money can be a strong motivator, it is by no means the only incentive that individuals and organisations respond to. Public recognition of outstanding performance can sometimes provide more powerful motivation. However, such awards can also be designed to encourage wider organisational behaviour change. Currently, an awards program that directly focusses DM does not exist. Establishing a public recognition for adoption of DM by consumers and utilities could be an effective complement to other policy tools.

Precedent:

The American Council for an Energy-Efficient Economy (ACEEE) has conducted two reviews of exemplary energy efficiency programs in an attempt to 'profile outstanding utility-sector energy efficiency programs that help customers lower their energy costs and reduce their energy use through improved energy efficiency' (ACEEE, 2010). While Australia does not have any reward program that is integrated into a larger program for DE, there are several notable environmental award programs, including the NSW Government's Green Globe Awards and the Commonwealth Government's Banksia awards. High profile events such as the national Banksia Environmental Awards provide a strong reinforcement for excellence in environmental performance in the business and public sector. The NSW Government's Sustainability Green Globes Awards now in their 20th year of operation, were initially created to recognise achievement of milestones in saving energy through the Government's Energy Smart Business Program.

6.8 Facilitation

Facilitation aims to make it easier for consumers, businesses and service providers to access and deliver DM options. This goes beyond information provision, but stops short of offering specific incentives, and is generally intended to support parties already seeking to adopt DM options. Facilitation is often aimed at reducing transaction costs, managing risk and building confidence. Facilitation can include some or all of the following:

- securing high level management commitment, to reducing administrative and cultural barriers
- audits, advice and technical assistance
- accreditation of service providers to provide potential clients with greater confidence (e.g. through the accreditation of solar panel installers)
- training and skills development (e.g. through the NABERS assessor training program)
- networking of customers and product and service providers (e.g. through seminars, conferences, websites)
- government endorsement of products, to inspire greater consumer confidence
- community engagement (e.g. though the 'Sustainability Street' program)
- standardised agreements for provision of DM services, in order to reduce legal and negotiation costs
- innovative procurement to accelerate product development such as more efficient or innovative appliances. See, for example, the Super-Efficient Refrigerator Program (SERP, also known as the 'Golden Carrot' Program) which was established in 1991 under the leadership of the US Environmental Protection Agency (Lee & Conger 1996).

While there are numerous facilitation initiatives provided by government and other organisations, there is no overall coordination or evaluation of their effectiveness in relation to DM. This leads to confusion, overlap, gaps and inefficiency.

6.8.1 Tool 10: Streamline network connection negotiation process

Description:

Establish a clear and consistent framework governing the processes and timeframes surrounding the negotiation of generator connection agreements between DG operators and local DNSPs. This tool is closely related to Tool #3 Streamline DG Licensing (Regulatory reform), however Tool #10 targets a different component of the connection process, (e.g. that of split incentives) and therefore Tool #10 is an tool to improve facilitation in concert with regulatory reform.

Responsibility:

As mentioned in Tool #3, the MCE's Network Policy Working Group (NPWG) released its final report in 2009, recommending a national connections framework for electricity distribution to be establish under the National Electricity Rules (Network Policy Working Group, 2009).

Why is this needed?

To connect generation equipment to the electricity network, an embedded generator must negotiate a connection agreement with the relevant Distribution Network Service Provider (DNSP), which sets out the connection costs and the standards of service that the connecting party will receive.

While some states establish principles for connection, there is generally no standard process for connecting distributed generators to the electricity grid, apart from small-scale solar PV which reflects the higher number and general consistency of annual connections for this type of embedded generation. For other DG options, each DNSP has its own requirements for connection of generation equipment to its network. In the case of technologies such as cogeneration, the process can be complex, time-consuming and expensive.

Another aspect of the complexity of the negotiation process is in managing the risks associated with the potential impacts on power quality at different network supply nodes. A key issue here is the existing vulnerability of the network to 'fault current' caused by supply disturbances within the electricity supply system, and how this may be affected when distributed generators are connected. Distributed generators have the potential to contribute additional fault current due to malfunctions in the generator or the network and this may lead to the existing network's prescribed 'fault levels' being exceeded. Deciding who should bear the responsibility for managing this additional fault current needs to be clarified, particularly in circumstances where the existing network fault levels are exceeded *before* the distributed generator connects.

A Review of Energy Markets in light of Climate Change Policy (AEMC, 2009c) found that streamlining AEMO's registration processes for small generators would better utilise small generator capacity in the NEM and strongly suggested that AEMO expeditiously progress a review to facilitate the use of underutilised embedded generators to increase the capacity available to the market. AEMO then sought to identify barriers to small generator participants in the NEM and related markets and develop a common framework for small generators in a recent discussion paper (AEMO, 2009a). Importantly, the scope of this small generation discussion paper does not cover network connection agreements, distribution network incentives, technical standards or networks price regulation (AEMO, 2010b), it does interface with other projects that are involved in this area including:

- Reliability Panel Technical Standards Review: minimum technical standards for connection
- Ministerial Council on Energy National Electricity (Retail Connection) Rules [Chapter 5A]: connection agreement and connection charges
- Australian Energy Market Commission rule change on the Demand Management Incentive Scheme.

AEMO's proposed design principles aim to reduce barriers in four main areas (AEMO, 2010c):

- Registration: simplifying, reducing redundancy and improving the cost-effectiveness of the registration process.
- Metering and settlements: collection of data, competition opportunities, developing consistent metering, reviewing the Rules and procedures around exempt networks and facilitating transfers of financial responsibility.
- Operations: aggregation for the purposes of ancillary services.
- Information Provision: clear information to small generator stakeholders on matter related to participation in the NEM.

An effective negotiation framework can help to improve certainty and reduce delays for parties negotiating a connection agreement, and thereby substantially reduce transaction costs for organisations considering distributed generation.

Precedent:

To facilitate a swift interconnection process for distributed generation, the Wisconsin Public Service Commission (PSC) has Rules for Interconnecting DG facilities (Chapter 119) that apply to all investor-owned utilities (WI Register, 2007), as well as DG interconnection guidelines (Wisconsin Interconnection Collaborative, 2004). The PSC has developed standard generation interconnection procedures, including forms and agreements for two size ranges of DG systems: 20 kW or less and between 20 kW and 15MW (WI PSC, 2004). Chapter 119 requires that each utility must have a designated DG contact, for which the PSC publishes the list. The time frames for DG interconnection in Wisconsin are legislated and therefore swift and efficient.

Germany passed the Renewable Energy Law (Erneuerbare Energien Gesetz – EEG) which provided unlimited access to the power grid. To meet the strong rise of DG interconnection, an electro-technical standardisation body has created grid codes and technical connection conditions for connecting power plants. In 2008, German Association of Energy and Water Industries released a directive for connecting generating plants to the medium-voltage power grid, based on the findings from the high voltage grid code experience. The grid code serves the network operator as well as the project designer and the manufacturer as a planning document and decision guidance (Troester, 2008).

In April 2014, the AEMC adopted a rule change to improve the network connection negotiation process for larger embedded generators to distribution networks. In November 2014, the AEMC, adopted a related rule change to help generators under 5MW connect to electricity distribution networks (AEMC 2014).

6.8.2 Tool 11: Decentralised Energy Ombudsman

Description: Establish 'DE Ombudsman' with the knowledge, technical engineering skills and authority to assist in dispute resolution between DE proponents and utilities. The DE Ombudsman could also assist in identifying gaps in skills that would be addressed by an industry-training program (Tool #13) and facilitating the network connection process (Tool #12).

Responsibility:

To be established by Commonwealth and/or state and territory governments. This role could in principle be fulfilled by the existing state-based Electricity and Water Ombudsman's Offices provided additional skills and resources were made available.

Why is this needed?

In most cases, the proponents of DE are much smaller and have far fewer resources than the energy supply businesses with whom they must negotiate. This disparity can lead to a perception of unfair treatment on the part of DE proponent. While the National Electricity Law makes provision for disputes and dispute resolution, these processes are generally so resource intensive that they are seldom used.

Precedent:

The establishment of a 'DE Ombudsman' modelled on the low cost conflict resolution approach adopted by existing energy and water Ombudsman's offices around Australia could provide an effective mechanism for streamlining negotiations over DE development.

6.8.3 Tool 12: Annual DE Review

Description:

State and territory governments should undertake and publish a comprehensive annual DE and DM review.

Responsibility:

Government energy, environment/climate change or industry departments

Why is this needed?

There are extensive institutional and industry resources devoted to understanding and developing electricity supply infrastructure:

- AEMO's Electricity Statement of Opportunities considers potential and opportunities in the electricity generation market
- AEMO's National Transmission Network Development Plan (NTNDP) considers potential and opportunities in the transmission sector
- The distribution annual planning reviews (DAPRs) (formerly called Distribution System Planning Reports in Victoria, Electricity System Development Reviews in NSW and Electricity System Development Plans in South Australia) provide forecast demand and capacity data
- The Australian Energy Resource Assessment provides a comprehensive overview of energy supply resources in Australia.

In contrast to these resources, the Annual DE Review would also provide a more comprehensive, systematic review of the state of DE and DM measures and opportunities for Australia. This Review would assist AEMO to better understand the potential for DE and DM and thereby meet its responsibility to ensure electricity system reliability.

The Annual DE Review would complement these reporting initiatives by providing (in relation to energy efficiency, distributed generation and peak load management):

a) a detailed and robust resource assessment of DE and DM potential, including expected economic and environmental costs and benefits to tapping this potential

b) an accurate assessment of current DE and DM practice

c) an overview of international best practice in DE and DM programs and policy

d) an evaluation of facilitation instruments for the adoption of DE and DM.

Precedent:

As noted above, there are numerous precedents for resource assessment on the supply side of the electricity industry. These precedents could provide a good model for developing a DE Review.

6.8.4 Tool 13: Training and skills development

Description: Establish an industry training program for DM options, building on existing 'green jobs' training efforts. The program is likely to cover different targeted streams for different types of participants.

Why is this needed?

Due to the relatively small number of DM projects undertaken to date in Australia, there is limited experience across the range of sectors required to successfully design, install and operate DM. This includes:

- Utilities – capacity to model and understand the implications of connecting embedded generators to the system, including realistic assessment of fault levels. This issue is related to perceived risks and network usage charges.
- Project proponents – many proponents are commissioning the design and installation of systems for the first time, and are not adequately informed of their needs, legal obligations or design requirements. A well-informed project proponent is critical to the success of future DM expansion.
- Engineering consultants – for example, trigeneration projects have reported issues with dramatic oversizing of plant for islanded systems due to design engineers not adequately understanding the year-round operation of trigeneration systems, and the interaction of the system with building management systems, particularly in highly efficient buildings. Note that these issues are of less significance if excess power can be exported to the grid and the plant can be operated at consistently higher load and also may not be such an issue for other technologies.

This issue of skills/experience shortage is particularly acute as it pertains to the operation of precinct scale DM, which has seldom been applied in Australia.

6.8.5 Tool 14: Integrated energy audits and technical support

Description:

Support the implementation of energy efficiency and load management measures by linking energy audits to technical support, incentives and high-level corporate commitment.

Responsibility:

Government energy, environment/climate change or industry departments

Why is this needed?

A series of market barriers have been recognised as providing a rationale for government support for energy audits:

- Business energy consumers have imperfect information about energy efficiency options. This relates to: energy operating costs when purchasing equipment, energy operating costs when operating, benchmarks for energy performance, lack of information rated to precedents, technologies and opportunities
- Business energy consumers' organisational failures often led to poor energy performance, and were aggravated by the corporate cultural barriers.
- Undervalued energy efficiency contributed to the business energy consumers' poor energy performance and necessitated government intervention.

It has subsequently been recognised that energy audits will be most successful where they are supported by detailed implementation support and crucially, corporate commitment to implementing identified savings opportunities.

Precedent:

Government support for energy audits has long been a government policy measure of in Australia. For example, in 1996, the Australian Government established a program to assist commercial and industrial firms to undergo an energy audit by an accredited energy auditing company (Harris et al., 1996). The audits provided the firms with a list of recommended energy improvements and a summary of expected costs and savings. The firm then elected whether to upgrade their systems. The Commonwealth Government subsidised 50% of the cost of the audit. Participation in the program was optional. One year after the audit, a follow-up questionnaire was sent to determine which energy savings measures had been undertaken. However, the rate of implementation of opportunities identified was found to be very poor. More comprehensive, outcome-focussed and successful programs have subsequently been established, including Commonwealth Greenhouse Challenge (which ceased operation in July 2009) and Energy Efficiency Opportunity Assessment (which ceased operation in 2013).

Current programs such as the NSW Government's Sustainability Advantage program only reach a small proportion of the market potential.

6.9 Information

Policy tools to overcome information barriers relating to DE and DM options include:

- benchmarking of energy performance to advise energy users of what constitute efficient levels of energy consumption in different contexts
- energy performance labelling on appliances and equipment
- performance reporting (without targets)
- community education and awareness campaigns
- energy management systems
- case studies.

Most of these are currently applied to varying degrees in Australia and each could be expanded. However, arguably the biggest information barrier in relation to DE and DM options is not at the consumer level, but at the policy level. Reliable information about the current practice and future potential of DE and DM options is not available. Given the likely potential for DE and DM options to deliver major economic and environmental benefits, this deficiency should be urgently addressed.

6.9.1 Tool 15: Better information on network constraints & avoidable costs

Description:

Require network businesses to provide easily accessible, up-to-date and relevant demand and network planning information.

Responsibility:

Network businesses are the only practical sources of information on network capacity and constraints. Following a detailed review, the AEMC proposed procedural changes regarding Electricity Distribution Network Planning and Expansion (AEMC 2009b), including information reporting requirements. DNSPs would then be required to publish information in accordance with this Rule. This created an opportunity to ensure improvements to network planning information disclosure in a useful form (AEMC 2012c).

Why is this needed?

Planning information can provide forecasts of network constraints and therefore economic opportunities for investment for proponents of DE. Not only is the key planning information required, but also a simpler and more accessible presentation of the network constraint information is also necessary. The AEMC Rule change, described below, provided an opportunity to achieve a nationally consistent reporting framework.

In 2009, AEMC suggested draft amendments to the National Electricity Rules that would require the establishment of a national framework for electricity distribution network planning and expansion. Importantly, this annual review process would also consist of a Demand Side Engagement Strategy and a Regulatory Investment Test for Distribution process to ensure DNSPs assess non-network alternatives in a neutral manner (AEMC, 2009b). The Engagement Strategy involves publishing a demand side engagement facilitation process, establishing and maintaining a database of non-network case studies and proposals and maintaining a Demand Side Engagement Register. The Distribution Annual Planning Report requires each DNSP to report on capacity and load forecasts, as well as actions taken to promote non-network initiatives, including embedded generation and smart grid technologies.

The elements required in this nationally consistent approach to annual reporting for distribution networks should be sufficient, providing that some guidance is issued, to ensure that such reports use a consistent format for ease of cross-comparison. Using this information as a foundation, Policy tools #16 (Consolidate and disseminate information on DM) and #17 (Resource Assessments and Case Studies) take the applicability of this information for the DM industry to the next level, by simplifying and interpreting the information in the DE context.

Note that evaluating potential avoidable network costs is a key focus of Network Opportunity Mapping Project using the DANCE model as described in Chapter 4.

Further, in the case of DG, where multiple proponents seek access to spare capacity in the network, a clearer and more transparent process is required to facilitate prioritisation of those projects. DG proponents have often been required to pay for network studies with no guarantee results will be accepted by the DNSP, so all of the risk is with the proponent.

Precedent:

Clause 5.6.2(b) of the NER requires that all TNSPs and DNSPs produce annual planning information on capacity constraints at the substation level and costs of solutions, however the presentation of this data in reports tends to be highly technical and inconsistent in format across DNSPs. This makes interpreting the data difficult for proponents of DE options.

6.9.2 Tool 16: Consolidate and disseminate information on DM

Description:

Develop relevant and accessible information resources on DE and DM, such as a website, apps or a 'Handbook' to provide information and guidance for DE proponents on areas such as: network connection processes (where relevant), costs, rights, responsibilities, financing, and legal requirements.

Responsibility:

Such an undertaking could be commissioned at the national level to complement existing electricity sector reform process or could be under the oversight of the Ombudsman. Alternatively or additionally, relevant state government agencies may be in a position to act independently, but should coordinate on collection and sharing of information to provide access to the broadest possible knowledge base.

Why is this needed?

During the research consultation process, stakeholders identified various impediments to DE due to a lack of clear, accessible and relevant information available to developers in the development process. This policy tool would act in concert with other regulatory, pricing, financing, facilitation and target setting reforms to help fill information gaps. This could be supported by a national 'DE advisory service' to accumulate expertise and provide advice to prospective DE service providers or investors.

The information resources should cover issues such as valuation of and available payments for electricity network benefits provided by DM, technical information and standards, negotiation processes, and planning requirements.

Precedent:

The US has a Database of State Incentives for Renewables and Efficiency that has comprehensive, up to the month updates on state, local, utility and federal incentives and policies that promote renewable energy and energy efficiency. It was established in 1995 by the US Department of Energy and is an ongoing project of the Interstate Renewable Energy Council.

6.9.3 Tool 17: Resource assessments and case studies

Description:

Establish an information 'clearing house' to publish comprehensive and accessible assessments of the opportunities for and successful case studies of decentralised energy and demand management in Australia.

Responsibility:

Government energy, environment/climate change or industry departments.

Why is this needed?

In many areas of DE, there is lack of well-documented precedents within Australia – that is, good examples of DE in operation across a range of scenarios and scales. The lack of precedents is related to the element of risk associated with new and innovative approaches, as perceived by potential proponents and financiers.

The lack of precedents raises informational and transaction costs and results in unnecessary duplication of costs for connection, power system analysis and testing, reliability.

Commonwealth, state and/or territory governments should coordinate with AEMO to collate and publish regular reviews and assessments of potential DE resources and case studies which present a concise, consistent and accessible description of opportunities. This would include location, timing, load reduction required and the value of such load reduction. The Statement of Opportunities should be complemented by an effective communication strategy to raise awareness of opportunities and how potential DE project developers can take advantage of them.

Governments should draw on lessons learned from international experience to assist the industry in approaching issues that are new to the local market environment.

Precedent:

The award winning Focus on Energy Program, in Wisconsin US, is a public private partnership funded by utility ratepayers. The Program certifies site assessors to conduct DE site assessments, subsidises site assessments for DE, provides grants for purchasing equipment and disseminates case studies on a wide range of DE options in residential, commercial, industrial and government sectors.

The Australian Centre for Analysis and Dissemination of Demonstrated Energy Technologies (CADDET) Program was part of an international network of information gathering, analysis and dissemination on energy technology, established in 1988 (Build Up, 2018). The program which concluded in 2005, provided access to the wide range of information on case studies, technologies and reports. The NSW Sustainable Energy Development Authority (SEDA) also published DE case studies, however this ceased with the Authority's closure in 2004.

In 2009, the AEMC's Review of National Framework for Electricity Distribution Network Planning and Expansion recommended that DNSPs populate their own public database of *selected* proposals/case studies providing examples of the project proposal and assessment process (AEMC 2009b). This was intended to help to provide better and more transparent and accessible information on DNSP processes.

6.10 Targets

Targets are often adopted by businesses, governments and individuals as a means of assigning a high priority to desired outcomes. Where the prevailing culture, habits or tradition are not delivering appropriate outcomes, targets can be an effective means of changing behaviour. For example, electricity distribution network businesses are usually subject to both regulated and organisational targets for reliability, safety, profitability and price. However, they generally do not have targets for DM or reducing greenhouse gas emissions. The regulator can use targets to drive the organisations to focus effort on these priority areas.

Targets also imply both measuring and reporting performance at regular intervals. Targets can be 'hard', such as the Commonwealth Government's Mandatory Renewable Energy Target, or 'soft', such as the Commonwealth Government's aspirational greenhouse target of reducing greenhouse gas emissions by 26% to 28% by 2030, or somewhere in between.

In order to stimulate DM options, Governments should set targets for DM development both in terms of energy (GWh per annum) and peak demand (MWp). These targets should be adopted as soon as possible, but need not necessarily be legislated. However, it is essential that annual targets be set, that performance towards these targets is publicly reported at least annually, and that a strategy for implementation is adopted, which includes clear accountabilities for performance.

6.10.1 Tool 18: Extend retailer energy efficiency targets

Description:

Extend mandatory energy efficiency targets for retailers to capture more of the available cost-effective energy efficiency potential.

Responsibility:

Commonwealth or state and territory governments.

Why is this needed?

There are a number of barriers to the uptake of energy efficiency in Australia, as discussed in Chapter 5.

A very effective policy tool to overcome these barriers is to mandate that energy retailers invest in energy efficiency. This can be achieved through a well-designed target scheme such as the UK's Energy Efficiency Commitment (see below).

Several issues with retailer energy efficiency obligations exist. For example, the savings are almost always estimated, so there is usually a gap between claimed and actual savings. Peak load is generally not included, so there is less of an incentive to target measures at peak times and in network constrained areas. In order to address these issues, it is important to consider concurrently implementing Tool #19, which suggests a broad government wide DE target across all sectors.

Precedent:

In 2007, the UK Government established targets for energy efficiency through its Energy Efficient Commitment (EEC). This commitment required energy suppliers to promote residential household efficiency improvements. Similar to a Renewable Energy Target, retailers were free to choose specific energy efficiency measures to meet their target. Typical measures deployed included insulation, low energy lighting or high efficiency appliances and heating systems. DEFRA (2007) states that, 'the EEC has been highly successful in delivering cost-effective energy efficiency improvements and has acted as a model for similar schemes in a number of countries within the EU'.

Similar schemes have since been adopted in Australia through the Victorian Energy Efficiency Target (VEET, now renamed Victorian Energy Upgrades), the South Australian Residential Energy Efficiency Scheme (REES) and NSW Energy Savings Scheme. However, each scheme is subject to various limitations. For example, the Victorian and South Australian schemes only apply to the residential sector. These schemes should be expanded and coordinated nationally and extended capture a wider range of sectors and energy saving technologies and behaviours.

6.10.2 Tool 19: Targets and reporting for DM development

Description:

State and local governments should establish annual targets for DM. This would involve a publicly announcement of annual targets for DM and annual reporting to track the progress.

Responsibility:

Commonwealth, state and territory and/or local governments.

Why is this needed?

There is significant inertia driving business-as-usual practices, and organisational goals and processes are usually set up to function most efficiently and effectively with the existing context. This can be described as a 'cultural' barrier to using DE solutions which makes it difficult for DE providers to displace business-as-usual alternatives. Where the prevailing culture, habits or tradition are not delivering appropriate outcomes, targets can be an effective means of changing behaviour.

In order to stimulate DM implementation, targets could be set both in terms of energy (GWh per annum) and peak demand (MW). These could be set by:

- a state government as a complement to Energy Efficiency Obligation scheme targets (see policy tool # 18). While ideally these targets would be legislated, this need not necessarily be so; or
- a local council in a publicly announced high-level (Lord Mayor/CEO) partnership with an electricity generation and retail or network business.

Complementary tools that would support ambitious targets could include:

- *Adopting a national high level energy savings goal*, described as a national energy intensity in terms of 1) GJ per capita; 2) GJ per $GDP; 3) value of annual energy saved ($); 4) value of annual infrastructure avoided ($); or 5) a 'loading order', similar to that adopted by California, which specifies the priority in which technologies should be deployed.
- Inserting an environmental and/or DM consideration into the National Electricity Objective.
- developing a Forward Capacity Market for demand management, similar to AEMO's Reliability and Emergency Reserve Trader (RERT) arrangements. However this market should be broader than just system security events.
- setting DM targets specifically for network businesses.

It is important to note that a medium or long-term target by itself is insufficient to support DM. Thus, as noted above, it is essential that *annual* targets are set; performance towards these targets is monitored and publicly reported; and clear accountabilities for performance are established.

The advantage of this target structure is that it is performance based, meaning the outcomes can be measured. As well, energy efficiency and DM have considerable potential to reduce peak load, so the opportunity to set targets for both annual GWh pa and peak MW savings facilitates economies of scale by maximising the cost-effectiveness against both measures.

Precedent:

More than 18 US states have legislated energy efficiency targets (GWh) and seven have mandatory peak demand management targets (MW) (ACCEE, 2010). Specifically, in California in 2009, the 3-year target was 1448 MW (3.7% of 2005 peak) and 7367 GWH (2.5% of consumption). The utilities pay penalties for under performance and incentive payments for over performance. The California Public Utilities Commission oversees the target. Other precedents are discussed in Dunstan et al, 2013.

In 2012, the European Union adopted its Energy Efficiency Directive which include a target and a set of binding measures to achieve a 20% reduction in energy consumption by 2020. As Rosenow notes “The most important Article of the Directive (Article 7) requires Member States to implement Energy Efficiency Obligations and/or alternative policy instruments in order to reach a reduction in final energy use of 1.5% per year” (Rosenow et al. 2017). In 2015, the European Union also adopted a policy principle of “Efficiency First” to give greater authority and priority to policies supporting decentralised energy. In 2016, the European Commission proposed an update to the Energy Efficiency Directive, including a new 30% energy efficiency target by 2030, and measures to ensure the new target is met (European Commission, 2016).

In 2015, the Australian Government adopted a National Energy Productivity Target to improve Australia’s energy productivity by 40 per cent between 2015 and 2030 (Australian Government 2015, p. 4). However, this target is not effective as a DM target as it does not include explicit targets for DM and does not attribute specific obligations to specific organisations.

6.11 Coordination

Coordination of effort is essential in any public policy activity involving multiple organisations. Given the scale and complexity of the task of rapid DM development, effective mechanisms to coordinate the strategy are particularly necessary in this area. One straightforward mechanism to achieve this coordination is presented here.

6.11.1 Tool 20: Agency to coordinate DM development

Description:

Nominate an agency with appropriate resources and authority to co-ordinate a DM strategy; this may require a significant institutional restructure.

Responsibility:

Commonwealth, state and territory and/or local governments.

Why is this needed?

The barriers impeding the development of DM and the mix of policy tools available to address them are complex. However, these complexities are no more challenging than those that have confronted other key government endeavours in the past, including the development of the electricity industry during the 20th century. A key strategy that is usually applied by government to address matters of major public interest is to appoint an appropriate agency to deliver the required outcome.

A suitable agency within government with appropriate skills, resources, commitment, and authority should be assigned responsibility for forming and managing a coherent DM Strategy. This could be a new or existing organisation (such as the Australian Renewable Energy Agency-ARENA), but is it essential that the successful development of DM is a core objective of the organisation and that it has clear performance indicators for success.

Precedent:

According to the World Energy Council, there are energy efficiency institutions and agencies nearly everywhere in the world:

> Almost all countries have set up specific institutions dealing with energy efficiency, such as energy efficiency agencies, either at the national level, or at regional levels or both, and more recently at local level. Although the legal status of these agencies is different from one country to another, their establishment almost everywhere clearly indicates that there is no contradiction between agencies and the market...The fact that most countries have set up an energy efficiency agency is in a way an empirical justification of their usefulness (WEC, 2008).

An example of effective coordination is Scottish Government's funding of an organisation to provide coordination to aid the development of a subset of DE options, specifically renewable energy and energy efficiency projects developed by community groups. The organisation – Community Energy Scotland – is independent of the Scottish Government, suggesting that non-government agents can also deliver effective coordination.

Community Energy Scotland delivers a variety of government funding programs incentivising DM for communities, and provides advice and assists in mediation between communities and utilities or technology suppliers where necessary. It also coordinates networking and learning between different projects, disseminates information on successful projects at an annual conference and works with the relevant parts of the Scottish Government to ensure the ongoing support for community renewable energy and energy efficiency projects (Community Energy Scotland, 2017).

The Australian Renewable Energy Agency (ARENA) plays a coordinating role in Australia for the renewable energy industry, which overlaps with the DE industry. ARENA could potentially have its mandate extended to take on a wider role related to decentralised energy.

6.12 Additional policy tools

The above discussion of 20 policy tools is not intended to be exhaustive. A selection of other potentially significant options to develop DM (that were suggested by stakeholders in the context of the Intelligent Grid research consultation process, or are relevant to this research area) are presented in the list below.

Table 6-2 Other possible policy tools to develop DE and DM

National energy goal	Adopt a national high level energy savings goal, described as a national energy intensity in terms of 1) GJ per capita; 2) GJ per $GDP; 3) value of annual energy saved ($); 4) value of annual infrastructure avoided ($); or 5) a 'loading order', similar to that adopted by California, which specifies the priority in which technologies should be deployed.
DE targets for network businesses	Set a performance-based target for DE for network businesses, where by the measure of success is whether growth in energy consumption is below or above the projections established at the start of the period.
Revise the NEO	Insert an environmental and/or DM consideration into the National Electricity Objective.
Forward capacity market	Developing a Forward Capacity Market for demand management, similar to AEMO's Reliability and Emergency Reserve Trader (RERT) arrangements, however this market would be broader than just system security events.
Regulate existing equipment	Regulate replacement of existing equipment rather than just new equipment efficiency standards.
Marketing and outreach education	Improve understanding and targeting of psycho-social barriers to behaviour change and engaging with consumer choice around DE. This may need to capture marketing and advertising knowledge and target the repositioning of EE as a brand. Government should critically evaluate who is the best agent to deliver such outcomes.
Facilitate landlord-tenant coordination	Explicitly tackle the landlord-tenant split incentive issue through facilitation, such as specifically targeting large building owners through a programmatic approach such as the City of Sydney's Better Buildings Program, which may include a broader rollout of Green Lease arrangements.

Mandate real time energy info for customers	Mandate real time usable energy information in homes (it was suggested that this process could be supported through the Ministerial Council on Energy's Smart Metering Decision).
Building design regulation	Network costs are driven by the forecast growth in peaks, which are strongly linked to cooling loads in buildings. Therefore, measures such as adding peak load shedding criteria to the Australian Building Code (National Construction Code) could be an effective means to integrate load management in the long term.
Regulate Capex and Opex	Adjust the regulatory treatment of network capital expenditure (Capex) and operating expenditure (Opex) to eliminate the preference for capital spending in the interest of profitability. This tool was a key topic of discussion at the 2010 National Trigeneration/Cogeneration Workshop in Sydney as part of the National Strategy for Energy Efficiency consultation process.
Promote development and uptake of more efficient appliances	This could take the form of rebates or other pricing interventions, information campaigns or facilitation to assist consumers in procuring more efficient goods, or raising of Minimum Energy Performance Standards.

6.13 Developing and applying an effective policy strategy

6.13.1 Planning and coordinating policy tools

In order to develop and apply an effective suite of a coherent and effective policy tools, it is useful to consider:

- how different policy tools work together
- which specific barriers each measure is trying to overcome
- approaches for addressing barriers given funding and resourcing constraints
- technologies targeted by each measure.

This section explores these issues to assist in framing the policy tools presented in the previous section.

The position of policy tools in the reform process is shown in Figure 6-11. Reform is most successful when policy tools are effectively deployed and linked between each stage of the reform cycle:

- **Adoption of aims** and goals to ensure coordination among efforts:
- **Selection and implementation** of the instruments to meet the aims;
- **Action**, meaning the implementation of DM; and,
- **Evaluation** of the mechanisms to ensure they are effective and successful.

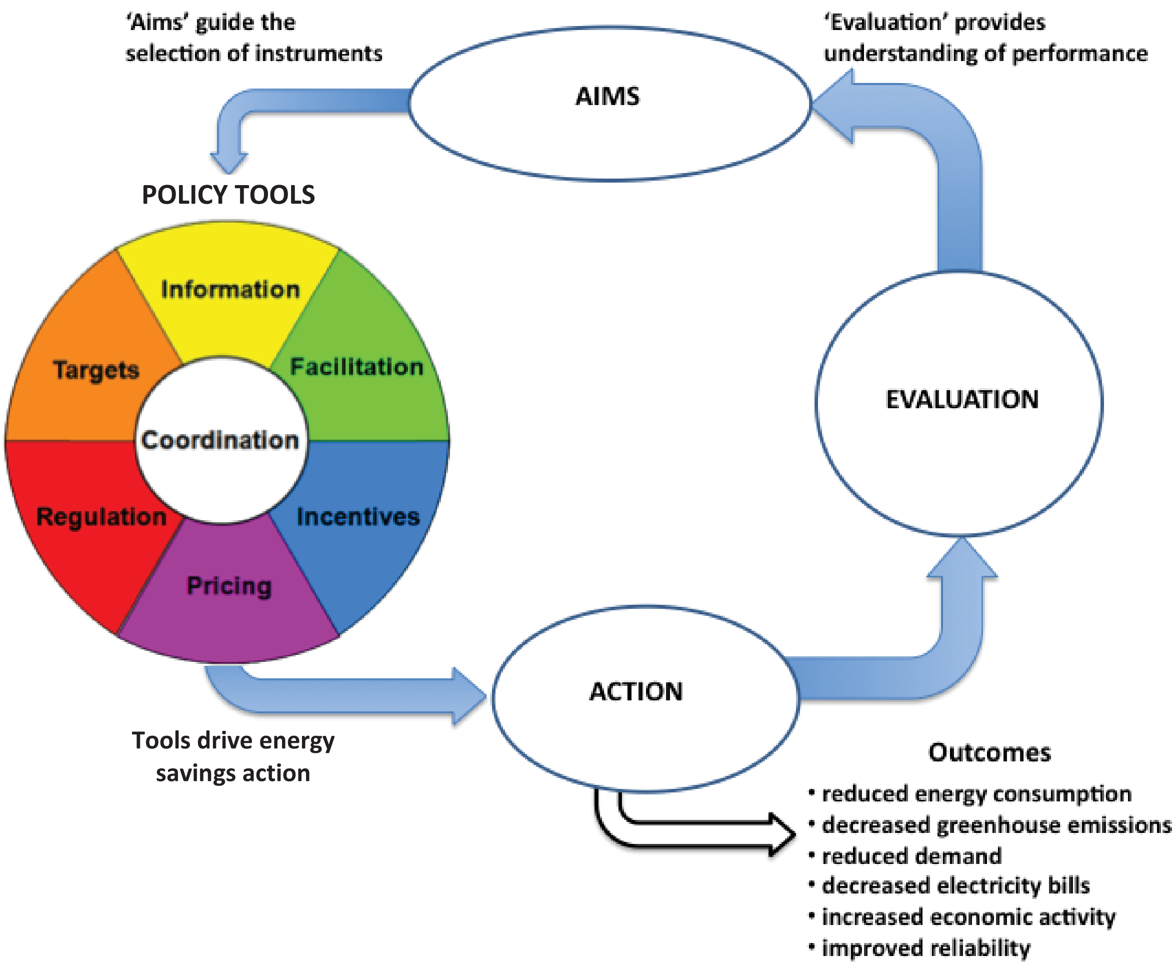

Figure 6-11 Context of policy tools in the reform process

(Dunstan, et al., 2010, p.24)

6.13.2 Addressing different forms of DM

It is also important to understand that not all policy tools target the three different forms of DE equally. That is, specific tools may target distributed generation, or energy efficiency or load management, or any combination of these. It is vital to achieve a balance between these different forms to unlock the full potential of DE. Table 6-3 indicates the relevance of each of the 20 policy tools to each of the forms of DE. When prioritising policy tools, a balanced representation of all three forms of DE should be achieved.

Table 6-3 Relevance of policy tools to different forms of Demand Management

Number	Policy Tool	Dist. Gen'n	Energy Effic'y	Load Mgmt
Regulation				
1	Decouple network business profits from electricity sales	✓	✓	✓
2	Fair treatment of DM in National Electricity Rules	✓	✓	✓
3	Streamline licensing requirements for distributed generation	✓		
Pricing Reform				
4	Impose a price on carbon pollution	✓	✓	
5	More cost-reflective network pricing	✓	✓	✓
6	Default Network Support Payments	✓		
Incentives				
7	DM Fund	✓	✓	✓
8	Reform feed-in tariffs	✓		
9	Public recognition and awards	✓	✓	✓
Facilitation				
10	Streamline network connection negotiation process	✓		
11	DM Ombudsman	✓	✓	✓
12	Publish a DM Review	✓	✓	✓
13	Training and skills development	✓	✓	✓
14	Integrated energy audits and technical support		✓	✓
Information provision				
15	Better information on network constraints and avoidable costs	✓	✓	✓
16	Consolidate and disseminate information on DM	✓	✓	✓
17	Resource assessments and case studies	✓	✓	✓
Targets				
18	Extend retailer energy efficiency targets		✓	
19	Targets and reporting for DM development	✓	✓	✓
Coordination				
20	Agency to coordinate DM development	✓	✓	✓

The 20 policy tools above may have varying levels of ease of implementation and level of impact. Figure 6-12 presents a matrix of the indicative ease of implementation and level of impact for each policy tool. The placement is qualitative only and is presented as an illustration for further consideration and discussion.

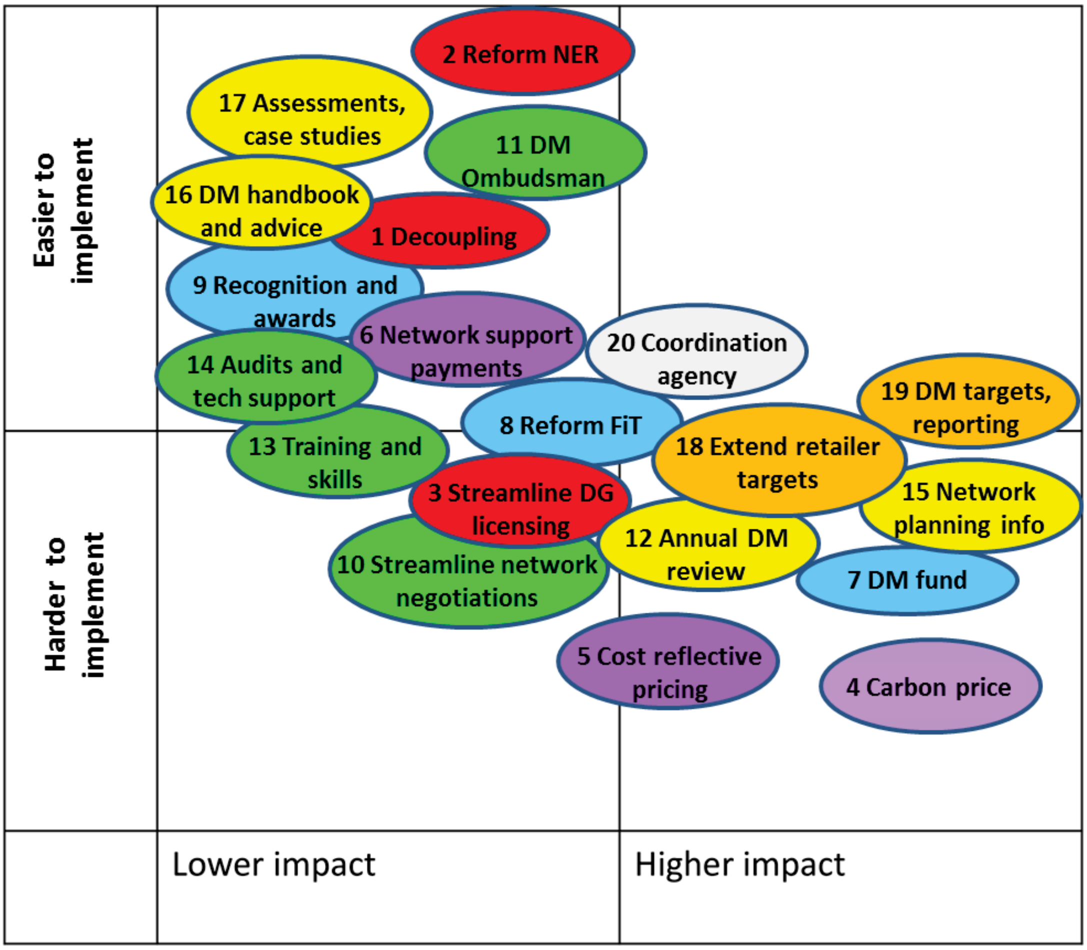

Figure 6-12 DM Policy tools matrix: Indicative impact and ease of implementation

6.13.3 Symmetric and asymmetric policy responses

In principle, the simplest approach to implementing policy tools for addressing institutional barriers to DE and DM is to identify the barriers and apply policies to counteract each barrier specifically. This represents a 'symmetric' response of addressing each barrier one by one. This can be an effective way of overcoming barriers, provided there is sufficient time, resources, personnel and, crucially, policy-makers' attention available to address all of these barriers simultaneously. The categories of policy tools are summarised in Figure 6-13 below, with policy tools that broadly correspond 'symmetrically' to identified barriers presented in corresponding colours.

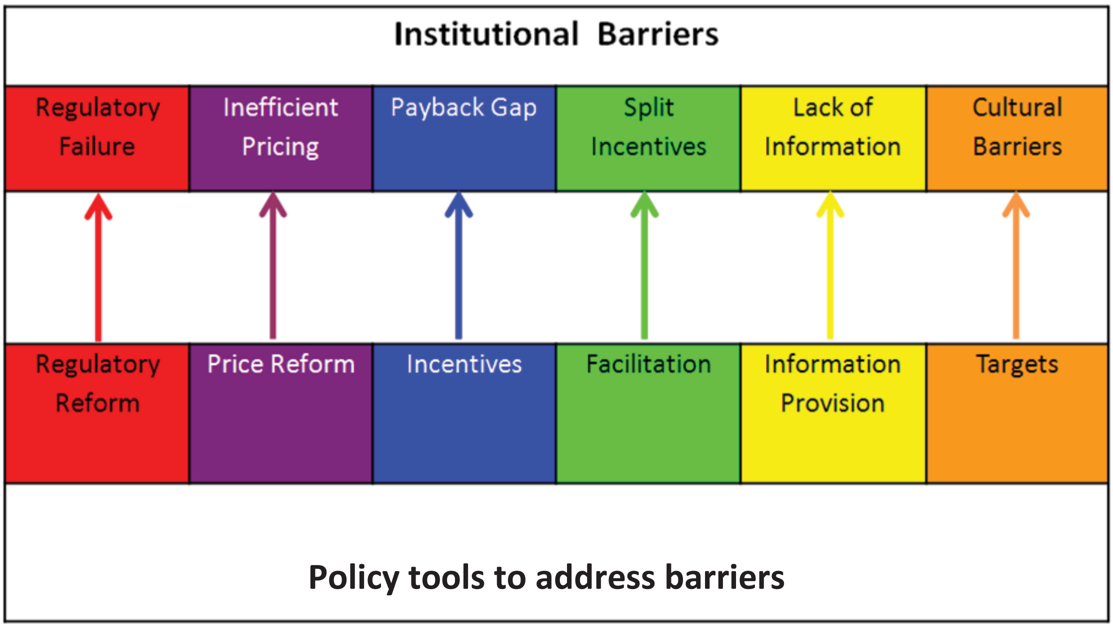

Figure 6-13 Symmetric policy response to address barriers

This *symmetric* policy response would involve each barrier being addressed with a proportionate and corresponding policy measure. In practice, this is seldom the case. For this reason, governments that wish to develop DE and DM options rapidly often apply an 'asymmetric' policy response of acting strongly in those areas where action is perceived to be easiest or most effective. Provided this limited number of policies is strong enough, it can in principle compensate for those barriers that are harder to address directly or are expected to take more time to overcome. Figure 6-14 illustrates what an asymmetric policy response might look like, given constraints in funding, resources or policy choice.

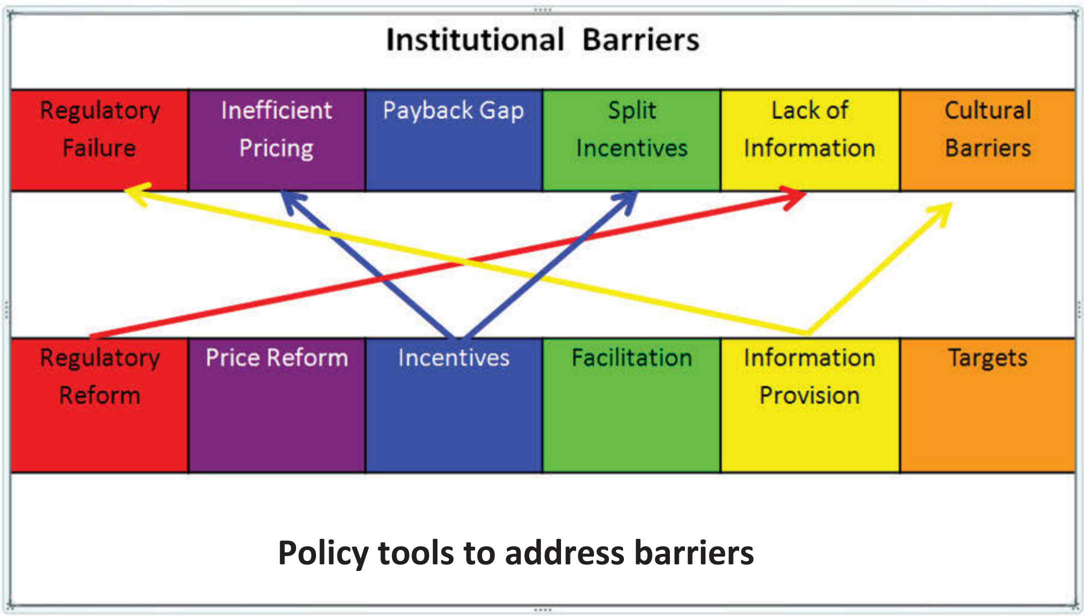

Figure 6-14 Asymmetric policy response to address barriers

An optimal *asymmetric* response would involve a mix of policy tools designed to maximise effectiveness given the available resources, even though this may mean some tools may seem excessive compared to their 'corresponding' barrier, while other barriers may not be directly addressed at all.

This chapter has not been structured with an explicit analysis of discrete barriers followed by a symmetric policy response. Rather, barriers are alluded to in the discussion of each specific policy tool. Multiple barriers are often addressed by a single policy measure. That is, the 20 policy tools presented in this chapter represent a possible strategic mix of policy instruments that might be applied to address the barriers to DE and DM. However, it is unlikely that the funds, resources and political will to implement *all* 20 of the policy tools will be available in the short term. Therefore, prioritising of tools is vital.

6.13.4 Coordination of policy implementation

Responsibility for implementing policy tools, is shared across a range of agencies, regulators, rule makers, policy makers, legislators and program agencies. From the national to the local level, these actors need to play complementary roles in policy development and implementation. This underscores the importance of effective coordination.

While the role of the electricity supply industry is crucial to successful DM development, this chapter has focused only on the public policy components. However, the more that the electricity supply industry is empowered and incentivised to overcome the institutional barriers itself, the less will be the need for intrusive policy interventions. The role of other stakeholders, particularly consumer advocates is also crucial, as effective policy cannot occur without effective stakeholder advocacy.

Policy makers must recognise that, just as the provision and management of energy is becoming more decentralised, so too the associated decision making must become more decentralised. Chapter 7 discusses a holistic conceptual framework for facilitating such decentralised decisions making, while still allowing coordination of the full range of policy tools discussed above. Chapter 8 reconsiders the wide range of policy tools discussed in Chapter 6 to suggest how a specific subset of tools could be applied to the Australian National Electricity market in a coherent way.

Chapter 7. Towards a Theory of Least Cost Electricity

'The philosophers have only interpreted the world in various ways; the point however is to change it.' – Karl Marx, *Theses on Feuerbach* (Thesis XI), 1845

7.1 The Australian electricity sector and theories of change

Chapter 2 outlined how Australia could achieve large economic and environmental benefits by using DM to accelerate adoption of DE in the electricity sector. Chapters 3 and 4 assessed the state of network DM and proposed a novel approach for identifying, quantifying and communicating the local network benefits of DM. Chapter 5 offered evidence and argument to explain what is obstructing us from tapping these benefits and Chapter 6 suggested policy tools to overcome these obstacles.

However, this thesis recognises that presenting evidence, advancing a robust argument and itemising a list of practical policy tools is unlikely to be sufficient to bring about change. If evidence, arguments and a clear policy agenda were sufficient, then the Australian electricity sector would have embraced least cost principles decades ago, when the case for least cost planning (LCP) was first articulated. The barriers to cost-effective DE and DM are more complex than this, and so are the solutions.

On the other hand, least cost planning has been adopted overseas, particularly in many states of the USA. In addition, some forms of DE have developed successfully in Australia. For example, DE in the form of rooftop solar has developed quickly in Australia in the past decade to achieve the highest penetration in the world, with one in five Australians now living under a solar roof (Vorrath).

So, while achieving effective change towards least cost outcomes may be challenging, it is clearly also possible. The key question then remains: *How can the electricity sector change to make least cost outcomes the rule, rather than the exception?*

This chapter pursues this question at a theoretical level, before Chapter 8 applies this theory at to the current Australian electricity sector. At the theoretical level, this chapter draws on the work of several theorists, including John Kingdon and Thomas Kuhn.

In his highly influential book *Agendas, alternatives, and public policies*, American political scientist John Kingdon describes the public policy reform process as being dependent on factors beyond the merits of the argument. In particular, he refers to 'institutional gatekeepers', 'policy entrepreneurs' and 'policy windows of opportunity' (Baumgartner, pp. 53-65). Kingdon notes that that creating of such windows of opportunity depends on the coincidence of a perceived need, a plausible solution and political will. Or as Paul Larkin describes it,

> [Kingdon] developed the theory that the timely confluence of "three streams" – the problem stream, the policy stream, and the political stream – is what creates the momentum necessary to place an issue on the public policy agenda, to move it from the "government agenda" (or "under discussion") box to the "decision agenda" box, and to lead government finally to change public policy (Larkin, p. 26).

Kingdon also refers to the role of randomness in policy outcomes. So, even when the policy case is clear and compelling, the institutional gatekeepers are amenable to reform, effective policy entrepreneurs are calling for change, and the window of opportunity exists, any given reform may still languish due to other factors. From this perspective, there is no specific set of circumstance that might exist, or that might be constructed in order to *guarantee* a given policy outcome, such as the adoption of least cost principles in the electricity sector. However, there are processes and conditions that can occur, or that can be cultivated, that would make such an outcome more likely.

In decades past, the 'problem stream' of electricity supply in Australian has been less prominent. For example, as noted in Chapter 1 and in Section 8.1.2 below, many of the adverse circumstances in the United States (controversy over nuclear power, damming rivers, acid rain, scarcity of energy resources, etc.) that led to the implementation of least cost planning in the 1980s, were not as conspicuous in Australia. However, there are other circumstances that have emerged in the Australian electricity sector in recent years (see below) that now are creating a powerful problem stream. However, as Kingdon describes, to bear fruit, this problem stream needs to be complemented with a strong policy stream and a strong political stream in order to create an effective 'window of opportunity'. The policy stream involves the development of viable and attractive policy solutions skilfully and promoted by policy entrepreneurs and the political stream needs to be facilitated by institutional gatekeepers.

Kindgon's model of reform is evolutionary in the sense that it sees reform as occurring through trial and error, in response to the environment, and also in the sense that it allows for gradual incremental change over time. Thomas Kuhn, on the other hand, focused on both evolutionary and revolutionary change in his seminal work, *The Structure of Scientific Revolutions*.

As a historian of science, Kuhn maintained that rather than involving a simple gradual accretion of knowledge over time, science consisted of two quite distinct processes. He saw most science as taking place within a prevailing orthodox intellectual framework, which he called a 'scientific paradigm'.

Kuhn defined a scientific paradigm as 'universally recognized scientific achievements that, for a time, provide model problems and solutions for a community of practitioners' (Kuhn, 1970, p. viii) and 'accepted examples of actual scientific practice—examples which include law, theory, application, and instrumentation together— provide models from which spring particular coherent traditions of scientific research' (p. 10).

A paradigm is a set of assumptions, beliefs, values and practices shared by the practitioners of a science. A paradigm describes what the discipline is, what problems it studies, what methods are applied, and what solutions are expected. Paradigms transcend theory itself to include a whole set of assumptions, beliefs and modes of thought and practice.

Kuhn called this paradigm-driven process 'normal science', that is, the gradual application and evolution of understanding, via 'problem solving' in the form of observation, experiment and interpretation. The practice of normal science acts to reinforce the prevailing paradigm, but over time, anomalous observation arise that are difficult to reconcile with the prevailing paradigm.

When anomalies and inconsistencies become so numerous or significant that they undermine faith in the prevailing paradigm, then 'normal science' can give way to what Kuhn called 'revolutionary science', where the prevailing worldview is replaced by a radically new paradigm. Examples of such scientific revolutions include the Copernican helio-centric revolution in astronomy, the Einsteinian relativity revolution in physics and the Darwinian revolution regarding the origin of species in biology.

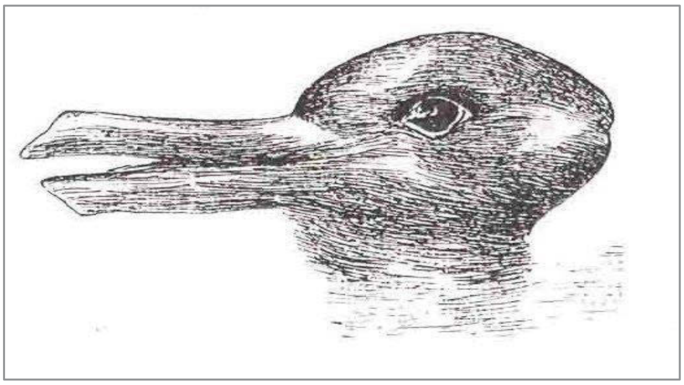

Figure 7-1 Mutually exclusive paradigms: the duck or rabbit illusion analogy

Kuhn referred to the duck/rabbit illusion as an allegorical illustration of the notion of the paradigm. The same image can be interpreted as a duck or a rabbit, but not both at the same time.

Figure 7-2 Elmer Fudd struggling with competing paradigms

This cartoon of the Looney Tunes character, Elmer Fudd, humorously illustrates the challenges of paradigmatic perception (Golden, 2018).

Kuhn's theory of scientific revolutions triggered something of a revolution in the philosophy of science, challenging as it did the dominant positivist conception of science based on objective scientists applying the scientific method to understand objective reality. While many of the details of Kuhn's theory are still contested today, the fundamental concept of the role of paradigms in shaping thought and knowledge has become very Influential in social sciences, as well as in the natural sciences.

While Kuhn's analysis was primarily focused on the physical sciences, it has been just as relevant in theorising in social sciences. The discipline of economics provides a pertinent example. In the late 19th century there was a transition from classical economics that focused on the problem of production to neo-classical economics that focused on the process and value of exchange. This transition was a paradigm shift. Similarly, the emergence of Keynesian macroeconomics and 'pump-priming' demand-side stimulus in the wake of the Great Depression was also a revolutionary change in prevailing economic thought. Consistent with Kuhn's conception of science as more of a stochastic zig zag rather that a gradual progression, the next big paradigm shift in economics was a reversion to 'supply-side' economics in the mid-1970s. Supply-side economics theorists such as Milton Friedman and Arthur Laffer critiqued the Keynesian paradigm and provided the intellectual economic foundation for monetarism, and the 'neoliberal' conservative economic paradigm of Ronald Reagan in the US and Margaret Thatcher in the UK.

These examples are relevant to this thesis, not only because they illustrate the ideas of Kuhn, but because they relate directly to the emergence of the prevailing economic theory focused on competition that currently dominates the electricity sector, and much other public policy, in Australia today.

As discussed in Section 8.1.1, the drive to establish competitive (and privatised) electricity market in Australia was inspired by similar reform undertaken by the Conservative Thatcher Government in the UK. In particular, the UK Government established a competitive wholesale generation market, or 'pool' in England and Wales in 1990 (IEA 2001, p. 29). Soon after, such ideas were promoted in Australia, both at the state government level, in particular in Victoria under Premier Jeff Kennett, and at the national level through initiatives such as the Industry Commission Inquiry into Energy Generation and Distribution (May 1990 – May 1991) (Industry Commission 1991b) and the Hilmer Inquiry into competition policy (Oct 1992- Aug 1993) (Hilmer et al. 1993).

The trend towards competition (and privatisation) expanded with the establishment of the Australian National Electricity Market (NEM) in 1997. Generation and retail competition was extended over the next 20 years to various degrees in Victoria, South Australia, NSW, ACT, Tasmania, Queensland and Western Australia, generation and retail privatisation in all states except Western Australia and distribution privatisation in Victoria, South Australia and parts of NSW. In this context of a strong focus on competition and privatisation, alternative approaches that were perceived to conflict with this theme, such as least cost planning, were marginalised.

However, this dominant paradigm of the last 30 years is now under challenge. The reliability of the system has been called into question by a series of supply interruptions and the price of electricity has risen sharply (see Figure 8-4 and Figure 8-5). Associated with this rise in prices, disconnections for failure to pay on time have increased, with significant adverse impacts on vulnerable customers. At the same time, as much of the industry has been privatised, the advocacy for further privatisation has become much more muted and the public opposition to past and future privatisation remains strong (Murphy, 2017; The Australian, 2014). Furthermore, the operation of the competitive market (including the 'merit order effect') when combined with other regulatory measures such as the RET and changes in technology has seen renewable electricity generation capacity increase while coal fired power station capacity has declined, including ten coal power stations closing in the past five years (Dunstan et al. 2017). These outcomes are far from what was promised, when the competition paradigm was proposed and then adopted in the 1990s. Judged against the explicit National Energy Objective (see Section 7.3.1) the National Electricity Market has been far from an unqualified success.

In short, the Australian electricity system is currently widely perceived to be in crisis (Energy Security Board 2017), and consequently the competitive market paradigm that dominates the electricity system is being challenged like no time since its emergence in the early 1990s. To consider this situation from a 'Kuhnian' perspective, the question is whether this crisis leads to a reconciliation of these 'anomalies' and 'inconsistencies', or whether it leads to an entirely new paradigm. To consider it from a Kingdon perspective, these circumstances create a major potential 'window of opportunity', which policy entrepreneurs may take advantage of to promote constructive policy reform.

Given these theoretical perspectives and recognising the current institutional context, this chapter builds on *the evidence and insights of the previous chapters* to offer a conceptual framework and reform program for the Australian electricity sector to reduce or avoid these unnecessary costs *for consumers* and to enhance sustainability.

The proposed framework and reform program, which can be described as 'least cost competition', aims to balance the roles of competition, planning and public accountability in delivering least cost electricity outcomes. In doing so, this reform program aims to facilitate a more balanced mix of centralised and decentralised energy options.

7.2 Towards a least cost balance for electricity

This chapter approaches balance and efficiency by drawing both on the principles of least cost planning (LCP), and on the dominant role of competition policy in energy market reform in Australia over the past 25 years. It is often assumed that LCP and competition are incompatible opposites. This chapter outlines an alternative perspective, setting out how these two conceptual and philosophical frameworks can and should be complementary in serving the needs of electricity consumers. Reflecting this analysis, this chapter proposes an innovative concept of '**least cost competition**' to reconcile the holistic scope of LCP with the market efficiency elements of the liberalised electricity market in the Australian NEM. In doing this, this chapter proposes reforms that are both conceptually efficient and practically viable in the 'realpolitik' of policy making in Australia. This discussion draws on the range of available policy options, and the reforms that are proposed take into account both the historical and current institutional context and proposes a strategy to bring about beneficial change.

7.2.1 What's in a name? 'Least cost planning' or 'integrated resource planning'?

The terms 'least cost planning' or 'integrated resource planning' are broadly interchangeable and are generally regarded as synonymous. However, the fact that both terms are commonly used warrants some examination and explanation.

'Least cost planning' puts the emphasis on the objective of minimising ***costs*** and maximising economic efficiency, thereby emulating the desired benefits of competitive free markets. The term 'Least cost planning' essentially implies: 'If you really want to reduce costs to energy consumers, then this is how to do it.'

On the other hand, **integrated resource planning** emphasises the blending of supply-side and demand-side measures and shifts the focus from minimising cost to optimising the mix of ***resources***. 'IRP' also implies that it is not just about minimising costs, but also maximising benefits and achieving a balance of competing objectives. As such plans are generally developed and implemented by utilities that recover their costs (and associated profits) from customers, these utilities may also prefer to shift the focus of attention away from ensuring 'least cost' and towards 'integrating resources'.

Both IRP and LCP can include or exclude social and environmental costs, so called 'externalities', depending on the context and the application. However, by shifting the focus away from costs, IRP deflects some of the ambiguity about which costs are being minimised, and thus avoids elevating cost as the primary objective. In any case, whether the objective is to optimise the resource mix or to minimise the cost, the objective needs to be clearly described and any relevant constraints need to be defined. For example, in all practical cases of LCP or IRP, one of the implicit or explicit assumptions that environmental and social costs are always included to the extent necessary to comply with the law.

In this thesis, I prefer to use the term least cost planning, as it has a clearer objective and is more consistent with the original concept (Sant, 1979). The term 'least cost planning' is also more clearly congruent with the operation of a competitive market and with the legislated objective of the National Electricity Market, as discussed below.

7.2.2 The recognition of supply bias and the emergence of least cost planning

The expansion of scale and scope in electricity supply following World War II transformed the developed world and brought immense material benefits to humanity. During this period of rapid economic growth and energy innovation, the value created by new and expanding applications of electricity, and the associated expanded supply of electricity, far exceeded its cost. Electricity was unambiguously positive, desirable and almost magically beneficial. Accordingly, there was limited focus on optimising the efficiency of its supply and even less focus on the efficiency of its use. The rate of growth in demand for electricity was often so high, that even in the seemingly unlikely event that surplus supply capacity could be provided, demand would 'soon enough' catch up (see Figure 2-2). The implicit axiom of 'build it and they will consume' seemed a reasonable rule of thumb. Indeed, up to the 1970s the issue of energy costs was broadly uncontroversial. Eto describes the period of the rapid expansion of electricity supply in the US as a kind of golden age:

> The history of the electricity industry up to the 1970s is characterized by harmony among utility, government, and individual interests. Increasing economies of scale

> in the technologies for power generation meant that increased electricity use led to lower prices for all… The primary challenge for regulators was to ensure frequent rates cases in order to lower rates as these economies of scale were realized. Utilities responded by actively promoting new uses of electricity in order to increase their profits; for example, advertising campaigns for all-electric homes were common in the 1960s. The federal government also promoted expanded use of electricity through subsidized electrification projects to bring electricity to rural areas. Electric utilities enjoyed a favorable public image (Eto 1996, pp. 4-5).

As shown in Figure 2-2, this seemingly endless growth was just a prevalent in Australia. In such a context, it is easy to understand how a strong emphasis on supply could prevail. However, the rapid development of large scale electricity generation eventually brought with it major problems and challenges, such as damming of rivers (for hydroelectricity), nuclear waste and radiation hazards and waste (from nuclear power), air pollution and acid rain (from coal fired power) and national security challenges associated with dependence on imported oil. The incremental value to consumers of additional electricity supply was declining, while the apparent costs were increasing. It was such problems, and in particular the advent of the first oil crisis in 1973 (precipitated by the Yom Kippur war between Israel and neighbouring Arab states, and the subsequently OPEC oil embargo), that inspired some stakeholders to focus on the potential of saving energy as a cost effective means of reducing these impacts. (See for example, Lovins, 1976).

In summary, the traditional approach of electricity planning, was firstly, to forecast future demand for electricity and secondly, to build the required electricity *supply at the lowest cost*. However, this approach typically does not deliver least cost outcome as it neglects lower cost, decentralised energy options, such as improved end use energy efficiency.

A change in perspective was forthcoming. The first phase of this interest in energy conservation in the mid-1970s involved an emphasis on information provision, encouraging consumers to use less energy (Sioshansi, p. 5, Nadel et al 1995, p.53). However, the limited effectiveness of this 'energy conservation' approach was soon apparent, and a second phase of proactive legislative change and financial incentives began to emerge in the late 1970s. For example, two laws were adopted by the US Government in 1978 that sought to shift the balance away from traditional centralised electricity supply.

> ‘The first [law], called the Public Utilities Regulatory Policies Act of 1978 (PURPA), required utilities to purchase power from non-utility generators at posted prices equivalent to the cost of power that the utility would otherwise generate. This law was an acknowledgment that the economies of scale underlying the natural monopoly in electricity generation had been exhausted and that utilities’ power to keep new generators out of the market was not in the public interest. The second law, the National Energy Conservation Policy Act of 1978 (NECPA) required utilities to offer on-site energy audits to residential customers. This law was an acknowledgment that saving energy could be cheaper than producing it.’ (Eto 1996, p. 5)

The fact that these two laws were introduced in concert underscored from the outset an understanding, at least in the US, that policy to encourage greater competition was compatible with, indeed complementary to, policy to support greater use of DE (and EE).

As the evidence mounted of the benefits of this more balanced approach to demand-side and supply-side resources, a coherent set of principles for optimising this balance crystalised in the concepts of ‘least cost planning’ (LCP) or ‘integrated resource planning’ (IRP). The creation of these terms has been attributed to Roger Sant’s (1979) report, *Least cost energy strategy: minimizing consumer costs through competition.* Sant traces his introduction to these issues to his appointment as Assistant Administrator of the Federal Energy Administration in 1974 by President Nixon (Sant, 2016). At the time of his appointment, he was a professor in the Stanford University Business School, and stated that, he ‘wasn’t sure I knew the difference between a BTU and a kilowatt hour.’ (Sant, 2016, p. 6)

LCP, or IRP, differs from the traditional supply-side planning approach by proposing that the costs and potential of all relevant options, including both supply and demand-side options, should be compared and combined to deliver an overall lowest cost outcome.

It is noteworthy that, while Sant’s paper is widely cited as the source of the concepts of LCP and IRP, the terms least cost ***planning*** and integrated resource ***planning*** do not actually appear in his report or his subsequent book. On the contrary, Sant emphasised the role of competition: ‘In this broader context, oil, for example, which has been protected from competition by past energy policies, would face stiff competition from new energy–efficient technologies, like those employed in the more fuel efficient automobiles.’ (Sant, 2016, p.6)

The central element of LCP is the capacity to compare 'demand-side' and 'supply-side' options. Electricity demand-side options (or 'decentralised energy options') include energy technologies that are applied on the customer side, or 'demand side', of the electricity meter. As noted in Chapter 1, decentralised energy options include end use energy efficiency, load management, distributed generation and storage. The key driver for the emergence of LCP was evidence that consumers and electricity supply utilities were failing to take advantage of these decentralised energy options, even when they appeared to be significantly lower cost than traditional supply-side options, such as building new centralised power stations or augmenting power networks.

Different jurisdictions have slightly varying definitions of IRP or LCP (see Harrington et al., 2006, pp. 6, 60-66). For example, the US state of Montana, has described the concept as follows:

> The goal of these integrated least cost resource planning guidelines is to encourage electric utilities to meet their customers' needs for adequate, reliable and efficient energy services at the lowest total cost while remaining financially sound. To achieve this goal, utilities should plan to meet future loads through timely acquisition of an integrated set of demand- and supply-side resources. Importantly, this includes actively pursuing and acquiring all cost effective energy conservation. The cost effectiveness of all resources should be determined with respect to long-term societal costs. (Montana Administrative Rules Service, 2001, s. 38.5.2001).

Nadel et al. (1995, pp. 20, 44) described the emergence of IRP as follows:

> In the United States, IRP was first developed and used in the Pacific Northwest in the early 1980s after the high cost of an ambitious nuclear construction program resulted in large electric rate increases and nearly bankrupted the regional power system. Government officials, utilities, and other interested parties looked for an alternative to the traditional power planning process that led to these problems and IRP was developed as a result. The genesis of the Northwest IRP is described in more detail in Chapter 3 of this manual …
>
> The Northwest Power Planning Council's 1981 Plan was 'the world's first IRP'

A brief history of the application of LCP principles in Australia is included in Section 8.1.2.

7.3 Principles of least cost planning

The principles of LCP were extensively developed throughout the 1980s. There are various formulations of the essential principles of LCP. The following is a typical such formulation.

Overall, the main characteristics of LCP (or IRP, which are now synonymous terms in the utility industry) in the energy sector have been summarized as follows:

1. Explicit consideration of **objectives**.
2. Explicit consideration and fair treatment of a **wide variety of options, including demand,** supply, transmission and distribution, and pricing alternatives.
3. Consideration of **environmental and other social costs** of providing energy services.
4. **Public participation** in the development of the resource plan.
5. **Analysis of uncertainties** associated with different external factors and resource options (Rufolo et al. 1995, emphasis added).

Hanson et al. have summarised the differences between traditional planning and least cost planning as follows:

Table 7-1 Comparison of features of traditional planning and least cost planning

Feature	Traditional Planning	Least-Cost Planning
Options	Supply options	Demand & supply options
Focus of economic cost analysis	Rate-payers	Multiple groups (society, program participants, rate-payers, individuals, etc.)
Objectives	Single	Multiple
Environmental quality	Meet minimum requirements	Improve quality beyond minimum levels
Judgment	Implicit	Explicit
Preferences	Implicit	Explicit
Reliability	Meet traditional standards	Choose appropriate reliability level
Role of public groups	Intervention	Participation

Source: Hanson et al (1991)

(Cited by Rufolo, 1995)

Figure 7-3 illustrates a summary of the principles and practice of LCP.

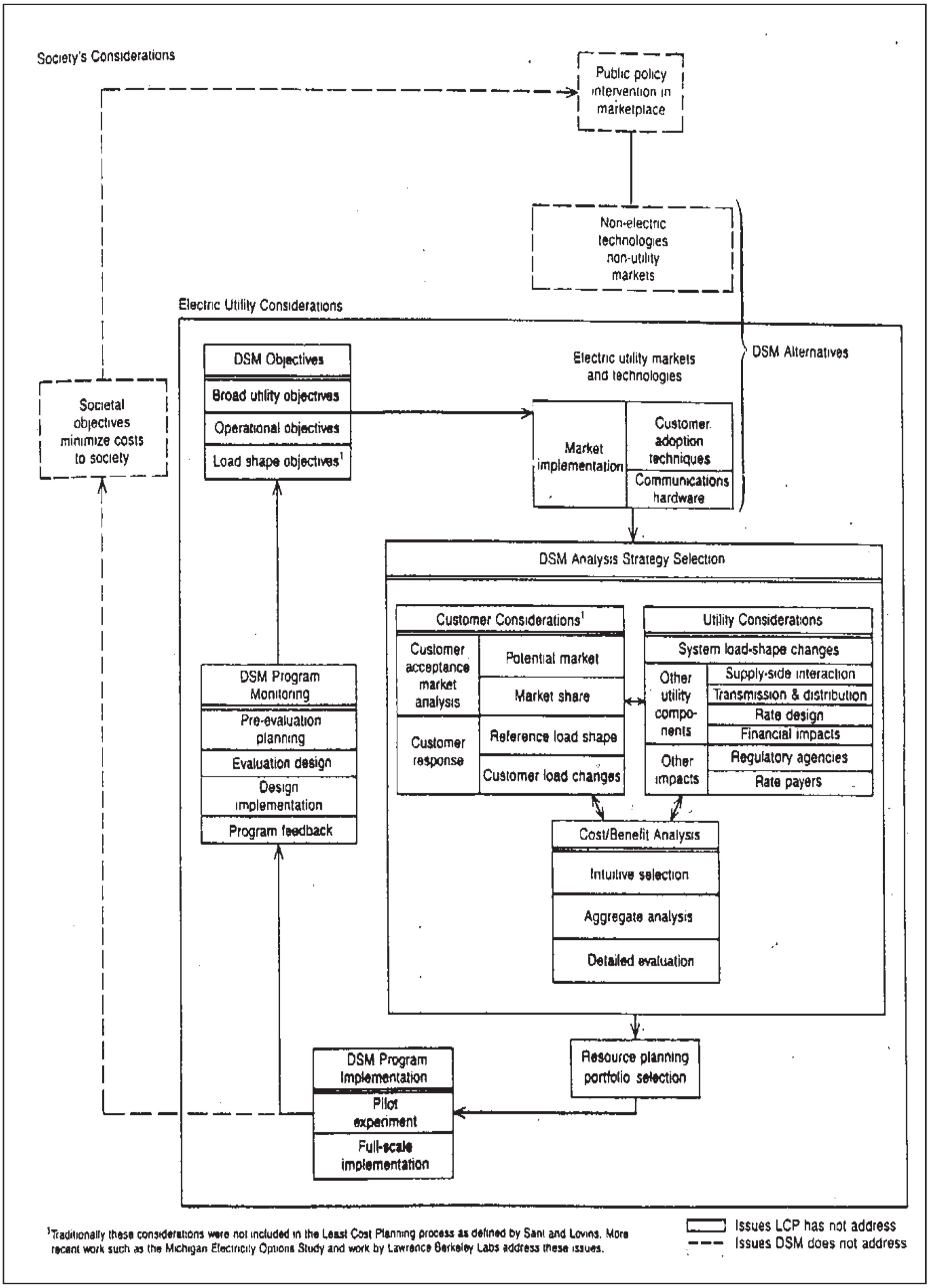

Figure 7-3 Integrated resource planning framework

(Gellings & Chamberlin, 1993)

Table 7-2 provides a summary of the least cost planning framework according to the US National Association of Regulatory Utility Commissioners (NARUC).

Table 7-2 Integrated resource planning framework

Least-cost planning usually consists of a number of discrete steps:

1. Identifying the objectives of the plan (e.g., reliable service, minimal environmental effects, low cost of environmental controls, meeting peak demand in a cost-effective manner, and a reasonable price for consumers).
2. Developing one or more load forecasts.
3. Determining the levels of capacity expected for each year of the plan.
4. Identifying needed resources (e.g., fuels, generating capacity, distribution capability, a manageable load shape, and perhaps periodic decreased demand).
5. Evaluating all of the resources in a consistent fashion.
6. Selecting the most promising options for fashioning an effective, flexible, and responsive plan.
7. Integrating methods of supplying needed power with methods for controlling and moderating demand.
8. Constructing scenarios, pitting the selected mixes of options against possible economic, environmental, and social circumstances.
9. Evaluating the economic and technical success of each mix of options under the circumstances of the various scenarios.
10. Analyzing the uncertainty associated with each possible plan of action.
11. Screening the alternatives to eliminate those that are not suitable.
12. Rank ordering the alternative courses of action.
13. Testing each alternative for cost effectiveness from a variety of viewpoints (e.g., the utility, ratepayers of different classes, and society).
14. Reevaluating the alternatives considering economic, environmental, and societal factors.
15. Selecting and approving a plan for implementation, one that most nearly satisfies all the objectives of the plan.
16. Developing a plan of action.
17. Implementing the plan of action to bring about the least-cost provision of electric power.
18. Monitoring and evaluating the operation of the utility under the plan and revising the plan as necessary.

(NARUC, 1988, pp. 2-3)

Today, least cost planning or equivalent processes are now applied in more than 35 states in the US, as shown in Figure 7-4.

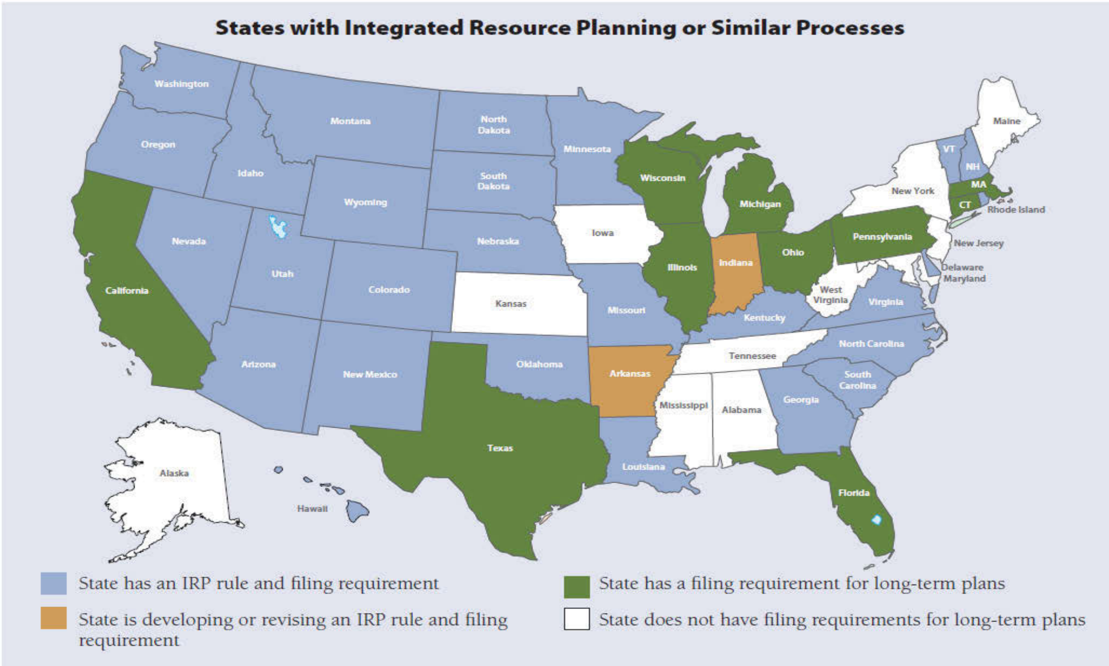

Figure 7-4 Application of LCP/IRP in the United States
(Wilson & Biewal, 2013, p.5)

These principles have been adopted in other countries' electricity sectors and have been extended to other areas of resource management that are characterised by centralised coordination and large economies of scale, such as gas, water, and transport. While LCP has long been discussed in Australia, it has not been implemented in the Australian electricity industry. (See Section 8.1.2 for a discussion of the history of DM and LCP in Australia.)

A key reason for the the disregard for LCP in the Australian electricity industry is the widespread view among policy makers that LCP is antithetical to, or at least inconsistent with, a competititive electrcity market. There are some valid grounds for this view, as will be discussed in Section 7.4. However, there is still much scope for, and major benefits to be gained from, applying elements of LCP in Australian competitive electricity market.

7.3.1 To what end? Setting objectives for the electricity sector

As noted above, the first principle of LCP is the explicit consideration of the objectives. All markets are designed with specific objectives, either explicit or implicit, in mind. In the electricity context, these objectives typically include meeting the 'energy service'[38] needs of a particular community, (or more narrowly, that adequate electricity is provided at a low price).

As illustrated in Figure 7-3, LCP is based on a framework of economic efficiency and cost–benefit analysis. The lowest cost mix of options that meets the given objectives is deemed the optimal, or 'the best' option. LCP essentially seeks to achieve an optimal balance of demand-side and supply-side options to meet specific objectives, and in particular it aims to minimise costs. The objectives of LCP may also include addressing environmental constraints by, for example, reducing greenhouse gas emissions.

As discussed in Chapter 2, greater uptake of DM and DE could deliver cost reductions of billions of dollars per annum for the Australian economy, without sacrificing the quality, safety, reliability and security of supply of electricity. This, of course, assumes that reducing costs, and thereby reducing bills, is a desirable objective. While this is might seem an uncontroversial assumption, minimising cost is not currently included in the Australian National Electricity Objective.

As noted above, the Australian National Electricity Market (NEM) *does* have an explicit objective, the National Electricity Objective (NEO) (AEMC, 2016a). In this respect, the NEM is consistent with the principles of LCP. However, the content and application of the NEO is not consistent with the other principles of LCP as discussed below. These include public participation, and consideration of all relevant options and all relevant costs.

The National Electricity Objective (NEO) states:

> The National Electricity Objective is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to –
> (a) price, quality, safety, reliability and security of supply of electricity; and
> (b) the reliability, safety and security of the national electricity system (South Australian Government, s. 7).

[38] The term "Energy services" is discussed in Section 7.3.2 below.

The NEO's primary focus is therefore on 'the long term interests of consumers'.

In principle, a focus on the 'long term' rather than 'short term' seems reasonable, but it also makes the NEO vague and it is hard to assess performance and policy against it. How long is 'long term'? How should decision-makers in the NEM balance clear short-term detriment against potential long-term benefit? The NEO is also vague in its use of the term 'consumers'. Is this intended as a theoretical economic concept, in which case only matters directly related to consumption by consumers are relevant? Or are subjective concerns of actual consumers as citizens relevant?

The NEO then goes on to prescribe the interests of consumers in terms of 'price, quality, safety, reliability and security'. This formulation precludes other potentially important criteria such as environmental sustainability, fairness, energy efficiency, and customer satisfaction. There is evidence that if consumers' own subjective assessments of their interests were to be considered, then they would prefer a broader set of criteria for the NEO. For example, a survey in 2010, of which I was a co-author, found that a majority of representatives of consumer organisations and other NEM stakeholders supported including 'environmental performance', 'protection of vulnerable consumers' and 'energy efficiency' in the NEO (Ison et al., p. 19).

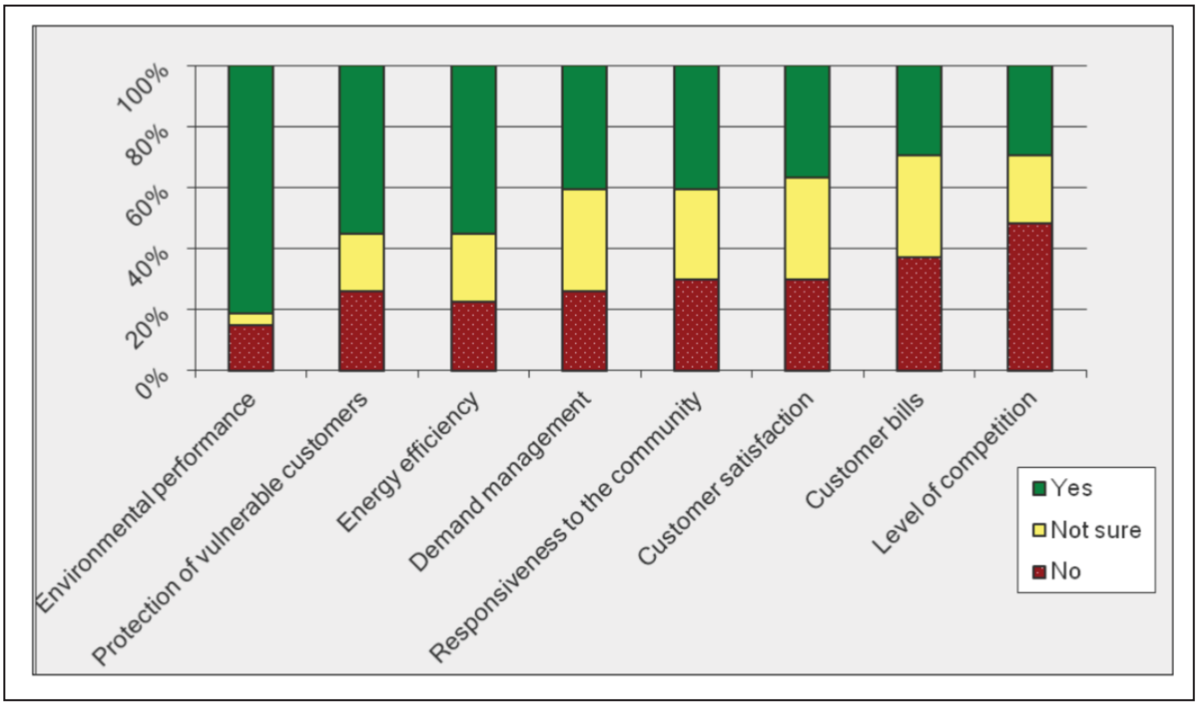

Figure 7-5 Which additional criteria to include in the National Electricity Objective?
(Ison et al. 2010, p. vii[39])

[39] Survey Question: "Of the other possible criteria, which should be included in the National Electricity Objective?"

The most contentious of the current NEO criteria is 'price'. The reference to 'price' rather than 'cost' implies that higher electricity bills are desirable, if they are accompanied with lower prices per unit of electricity consumed. In the current context of the increasing uptake by consumers of decentralised energy, with the goal of reducing electricity *bills* rather *prices*, this focus on price is increasingly outdated and problematic.

However, the major flaw in the NEO is arguably, not that it has a focus on price rather than cost, but that it is vague and ambiguous. A balance between several objective criteria is reasonable, but the absence of clear guidance on how these criteria should be weighted, and how performance against these criteria should be assessed and reported, is a major flaw.

Achieving a better balance requires a framework for assessing what is 'better' or 'the right' balance. When one is making this assessment, economics can provide a theoretical framework of efficiency (or pareto optimality) – achieving the best possible outcome given scarce resources (Robbins 1932, p. 15).[40] Within this framework, an approach that uses fewer resources to achieve the same outcome is considered preferable to an approach that uses more resources[41]. However, while economic efficiency can inform decisions about how best to meet given outcomes or objectives, it can tell us little about what outcomes or objectives to pursue. In other words, this 'positive' perspective of economic optimisation must be grounded in a 'normative' perspective of what outcomes are desirable. The absence of a mechanism to engage consumers in defining what they themselves regard as 'in the long term interest of consumers' is a key flaw that highlights the need for effective public participation and accountability, as discussed in Section 7.3.4 below.

It is also noteworthy that the NEO is a relatively recent addition to the NEM. While the NEM was first conceived in the early 1990s and formally established in 1998, the NEO was only included in the National Electricity Law in 2005. Indeed, the first objectives of the national electricity market which were 'endorsed by the Heads of Government of New South Wales, Victoria, Queensland, South Australia, Tasmania, the Australian Capital Territory and the

[40] Consistent with Lord Robbins' conventional definition of Economics as "the science which studies human behavior as a relationship between ends and scarce means which have alternative uses."

[41] Note: that this does not mean that non-market "goods" such as environmental quality, are necessarily ignored. Rather, it simply means that the assessment of what is optimal is based primarily on quantifiable values, consistent with a conventional benefit cost analysis. Values that are not easily quantified can either be included via a stipulated environmental standard or other constraint, or be included in the analysis via a proxy value for non-market goods, such as a price on carbon emissions.

Commonwealth' in 1992, were strikingly different to the current NEO (NGMC, 1992, foreword). The Objectives of the National Grid Protocol included the following:

> to encourage the most efficient, economic and environmentally sound development of the electricity industry consistent with key National and State policies and objectives; [and]…to provide a framework for long-term least cost solutions to meet future power supply demands including appropriate use of demand management (National Grid Management Council, 1992, Foreword).

The same document stated that the objectives of the National Grid Management Council were:

> to encourage and co-ordinate the most efficient, economical and environmentally sound development of the interstate electricity supply industry having regard for key National and State policy objectives (National Grid Management Council, 1992, p. 1).

Such objectives are much more consistent with least cost principles than the current NEO.

Nevertheless, despite its flaws and possible flaws in the process through which it was adopted, the NEO reflects the outcome of the democratic legislative process in Australia.

Within modern market democracies, the authority for setting the objectives for markets derives from the general 'will of the people', or the community, generally mediated via their elected representatives or government. This form of authority is a relatively new development in human history that has accompanied the rise of democracy. Prior to the emergence of modern democracy, such authority derived from the lord, the monarch, the church or 'the will of God'. Even today, some 'neoliberals' or 'market fundamentalists' believe that specifying market objectives is redundant, as it is up to individual market participants to express their desires via the market. In this view, market objectives are not predefined but emerge from the operation of the market, or in other words, 'the will of the market'.

It is noteworthy that the narrow scope of the NEO is unusual by international standards. Even the UK framework, which was in many respects the template for the Australian NEM, has a much wider set of objectives, as shown in Figure 7-6.

Ofgem regulates Great Britain's gas and electricity markets, to protect the interests of current and future consumers. Through our regulation, we aim to deliver five outcomes for consumers:

- Lower bills than would otherwise have been the case
- Reduced environmental damage both now and in the future
- Improved reliability and safety
- Better quality of service, appropriate for an essential service
- Benefits for society as a whole, including support for those struggling to pay their bills

Figure 7-6 UK electricity system objectives

(OFGEM, 2017, p.6)

7.3.2 Supply and demand – balanced assessment of energy service options

Fundamental to the principles of LCP is the concept of 'energy services'. 'Energy services' recognises that unlike many other goods like water, food, shelter and clothing, energy does not offer direct benefits in consumption. Rather, we purchase and consume energy, produced from sources like natural gas, petroleum, coal and electricity for the services that it provides, such as transport, cooking, illumination, heating and cooling.

The concept of energy services reflects the principle that there are many ways of providing such energy services. For example, a warm home can be provided by supply-side options such as burning wood, or gas, or oil, or powering a reverse cycle air conditioner, or by demand-side options, such as building a well-insulated, energy-efficient, passive solar home that need not consume any purchased energy at all.

The essence of least cost planning is to examine all options relevant to a given objective or set of objectives, and to choose the lowest cost option or mix of options. The most common way that the electricity system falls short of achieving this least cost goal is by neglecting to consider all relevant options. The options most commonly overlooked are on the demand side – that is, decentralised energy resources. In order to redress this oversight, LCP has developed a series of economic assessment tests to compare the costs and benefits of decentralised energy to those of traditional supply-side options. These cost effectiveness tests are described below.

Cost-effectiveness tests

Last cost planning typically applies up to six cost-effectiveness test measures. These tests are used primarily in the design and assessment of decentralised energy options to include in a least cost plan, but are also used ex post in the measurement and evaluation of options and plans. The following definitions have been drawn from the *California Standard Practice Manual: Economic Analysis of Demand Side Programs and Projects* (State of California 2002). Usually, one of these cost effectiveness tests is set as the 'primary test' for decision making about preferred options.

1. **Participant test**

   This test is the threshold test for assessing how the energy *option* affects the customers participating in it. For example, if offering a rebate for more efficient lighting or for an interruptible air conditioning scheme were to leave the participants financially worse off, then this option would fail this test. As participants are generally not forced to participate in such options, failure of the participant test would indicate that an option would be unlikely to attract participants and this would generally preclude the option from being adopted or included in a least cost plan.

   The Participant Test is not just a pass/fail test. While a positive assessment against the Participant Test is desirable in order to justify an option, if the benefit cost ratio for the Participant Test is excessively high then it risks both not being least cost, but also raising the cost of the measure to the utility and therefore to their customers, undermining other tests such as the Rate impact Measure test.

2. **Ratepayer impact measure (RIM) test**

   The Ratepayer Impact Measure (RIM) Test considers options from the perspective of utility ratepayers as a whole, that is, both participants and non-participants in the option. This is a more exacting and relevant test for the option than the Participant Test, as it assesses whether it is in the interests of ratepayers (that is, customers) as a whole. If the net benefits for participants, as per the Participant Test, outweigh the net costs or ‘disbenefits’ for the non-participant ratepayers, then the result of RIM Test may still be positive or ‘passed’.

Note that the RIM test divides the net costs and benefits by the volume of energy sold or consumed, which means that if the option leads to a lower volume of energy sales, then this tends to raise energy rates, that is, the net cost per unit of sales. Consequently, an option, such as an energy efficiency measure may lead to lower average energy bills, but higher average energy rates or prices. This example illustrates how the choice of a specific objective can have a powerful impact on which options are preferred.

3. **Total resource cost test**

The Total Resource Cost (TRC) Test is broader still than the RIM test as it considers factors and perspectives beyond the utility’s current ratepayers. It is generally preferable to the RIM test in that it does not share the intrinsic bias against measures such as energy efficiency that would reduce sales volumes. Other perspectives and factors that the TRC Test may consider include:

- the cost to the participant of participating in the option, such as any financial contribution they make to the cost of implementation. For example, if they receive a subsidy on installing a more efficient refrigerator, the unsubsidised portion of the cost of the refrigerator should be included.
- the value of any ancillary benefits to the customer of participating in the option, such as the value of a more comfortable home or less food waste as a result of installing a new, more efficient refrigerator.

The TRC is in principle a relevant test for the option as it seeks to consider all costs and benefits. For this reason, the TRC Test is often adopted as the primary cost effectiveness test in assessing DE options. However, in practice, it can also be challenging as it seeks to assess a wide range of factors that are hard to quantify. This makes the TRC Test more resource intensive to undertake as it requires more data to be collected and verified. It also makes the TRC Test more prone to uncertainty, differing interpretations and disputes. The uncertainty has to be managed by utilities and by DE proponents, raising the effective cost of DE and reducing its viability and uptake.

4. Societal (cost) test

The societal test is a variation of the TRC, and shares many of the benefits and disadvantages of the TRC test. The Societal Test further expands the assessment perspective to society as a whole. The Societal Test differs from the TRC Test in two key ways:

1) the Societal Test generally uses a societal discount rate, which tends to be lower than the average cost of capital discount rate which the TRC generally uses

2) the Societal Test also includes all quantifiable external costs and benefits attributable to option. These can include, for example, avoided pollution, 'water savings, detergent savings, and other non-energy benefits' (Daykin et al., 2012).

5. **Program administrator cost test (PACT, a.k.a. Utility Cost Test, UCT)**

The program administrator cost test (PACT) is a much narrower cost effectiveness test than the TRC test. It only considers the cost to the entity supporting the DE option or administering the DM program. As this entity is often a utility, particularly in the US where the test was developed, it is often also referred to as the 'Utility Cost Test' (UCT). It does not consider the costs or benefits to the participant or the ratepayer, and it does not consider the broader environmental and social costs, except to the extent that they are borne by the program administrator or utility (which of course, means these otherwise external costs are internalised). So, while the narrow scope of the PACT does not accommodate external environmental and social costs, nor does the standard TRC.

6. Resource value test and choosing a primary cost effectiveness test

The momentum towards adopting simpler, more streamlined cost effectiveness tests has recently accelerated with the development of the *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources.* The objective of the new approach is set out in the document's Executive Summary:

> This National Standard Practice Manual (NSPM) builds and expands upon the decades old CaSPM [California Standard Practice Manual], providing current experience and best practices with the following additions:

• Guidance on how to develop a jurisdiction's primary cost-effectiveness test that meets the applicable policy goals of the jurisdiction.[42] The guidance also addresses the difficulties jurisdictions have had in consistently implementing concepts presented in the CaSPM.

• Information on the inputs and considerations associated with selecting the appropriate costs and benefits to include in a cost-effectiveness test and accounting for applicable hard-to-monetize costs and benefits, with guidance on a wide range of fundamental aspects of cost-effectiveness analyses (Woolf et al. 2017, p. vii).

This approach aims to resolve the debate about which test should be the primary cost effectiveness test by proposing that jurisdictional governments and regulators select their own "Resource Value Test" which is describes as follows,

> The RVT is the primary cost-effectiveness test designed to represent a regulatory perspective, which reflects the objective of providing customers with safe, reliable, low-cost energy services, while meeting a jurisdiction's other applicable policy goals and Objectives. As described in detail within the NSPM, each jurisdiction can develop its own RVT using the Resource Value Framework.
>
> … Depending on a jurisdiction's energy and other applicable policy goals, the resulting RVT may or may not be different from the Traditional cost-effectiveness tests. Put another way, it is possible for a jurisdiction's applicable policy goals to align with one of the Traditional CaSPM tests, in which case its RVT will be identical to one of those tests. However, it is also possible—and indeed likely in many cases—that a jurisdiction's energy and other policy goals will not align well with goals implicit in any of the traditional tests. In such cases, the RVT will be different than all the traditional Tests. (Woolf et al. 2017, pp. ix-x)

Not surprisingly, when a given option is assessed against different tests, it delivers different results. Accordingly, a single test is typically assigned as the primary test for the purposes of decision-making. In the early years of LCP, the most common choice for the primary test was the Total Resource Cost (TRC or societal test), however, in later years the PACT or UCT has gained favour. This shift is due to pragmatic streamlining undertaken to reduce transaction costs and to provide a fairer system.

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[42] "The NSPM uses the term "jurisdiction" broadly to encompass states, provinces, federal power authorities, municipalities, cooperatives, etc"

At first glance, the narrow focus of PACT may suggest that it is inappropriate for evaluating cost effectiveness. However, the narrow focus on the cost to the administrator or utility is actually analogous to how a utility assesses the business case for supply-side options. Consequently, adopting the PACT to assess DE options can make a least cost comparison relatively straightforward. Moreover, the simplicity of the PACT reduces the scope for uncertainty, interpretation and dispute, which reduces transaction and risk management costs.

There is another more practical reason why some analysts prefer the PACT to the TRC test. While the TRC is, in principle, intended to be balanced in taking account of all relevant cost and benefits, in practice there appears to be a bias against DE options. For example, while the participant costs of DE options are often estimated in the TRC, the participant benefits of DE options seldom are.

For these reasons, energy policy makers and regulators are increasingly adopting the PACT (or UCT) as the primary cost effectiveness test, or Resource Value Test, in evaluating DE options.

As Neme and Kushler (2012) have noted:

> While the majority of jurisdictions use the TRC, a few notable exceptions point toward a newer trend of using the UCT. Utah relied on the TRC for a number of years, but replaced it with the UCT in 2009. Michigan, a state that adopted energy-efficiency standards in 2008 along with Pennsylvania and New York (TRC jurisdictions), prescribed the UCT as the cost-effectiveness threshold utilities must meet. California has also shifted to a weighted TRC and UCT test, rather than the TRC alone (Daykin et al. 2012, p.2)

The current use of primary cost effectiveness tests is shown in the table Table 7-3 below.

Table 7-3 Primary LCP Cost Effectiveness test as applied by states in the USA

Table 1. Primary Cost-Effectiveness Test by State

All tests	TRC/SCT Primary Threshold	UCT Primary Threshold
IN, IA, NC	CA[2], CO, DE, FL, IL, ME, MA, MN, MO, NH, HJ, NM, NV, OH, OR[3], PA, RI, VT, WA, WI	CA, CT, MI, OR, TX, UT

(Daykin et al. 2012, p.2)

Some experts, such as Neme and Kushler have advocated that all jurisdictions should adopt the PACT as the primary test: 'This all suggests that a switch to primary reliance on the PACT for utility resource selection (supplemented as necessary by the Societal Test) is the best course of action today (Neme and Kushler, 2012).

Another important practical consideration is how the cost effectiveness tests are applied. Given that the decentralised energy options tend to be relatively small, high transaction costs can have a significant detrimental impact on cost effectiveness. There is little point in identifying a least cost solution that saves half a million dollars if the process of identifying, assessing and comparing it costs twice that amount. This has led to proposals to streamline the application of cost effectiveness tests, as discussed below. Fortuitously, these newer approaches are more consistent with competitive market processes.

Efficient pricing

One of the key demand-side options that is often overlooked is price reform. Even if the *average* price of electricity remains constant, changing the *structure* of prices can have a powerful impact on demand. Raising prices at times of peak demand and reducing them at off peak times can encourage behaviour change and other measures by customers to shift demand away from the peak, reducing or avoiding the need for the supplier to invest in expensive new capacity.

To be efficient, prices should reflect the marginal cost of supply. At times of peak demand or other supply constraints, the incremental, or 'marginal', cost of supply may be very high, as it may be very costly to provide additional capacity for a short period. Accordingly, the efficient price of power at these times would also be very high. Such high peak prices would send a signal to consumers to do whatever is possible, at a cost up to this higher price, in order shift or reduce demand. On the other hand, at off peak times when there is abundant spare supply capacity, the cost of incremental supply may be very low, zero or even negative. Consequently, the efficient price at such times would be very low.

So, in order to comply with the LCP principle of examining all options relevant to providing the required energy services, it is crucial that the options considered include all feasible pricing reform options as well (see also Section 6.6.2 for discussion of cost-reflective pricing).

7.3.3 Externalities – in or out? Environmental and social costs of providing energy

As noted in Section 7.2.1, one of the likely reasons that the term IRP has become more prevalent than LCP is that IRP puts the emphasis on 'integrating resources', while LCP puts the emphasis on 'least cost'. For many advocates of cleaner energy options, the focus on minimising costs is part of the problem, as it ignores the 'externality' costs of the impact of energy supply on the environment and society. However, ignoring such environmental and social costs does not mimimise costs; it merely means that these costs are simply borne by other parties, rather than the one creating it.

Least cost planning should in principle include these external costs in the analysis. There are however, three problems with this approach. Firstly, there are difficulties in estimating the value of these external costs, and the estimates can be very contentious. Secondly, there is often a view in policy circles, particularly in Australia, that such external costs are best addressed outside of the electricity market framework. It is for this reason that environmental and social costs were deliberately excluded from the National Electricity Objective. To the extent that these costs ***are*** effectively accounted for outside the electricity market structure, this can be effective. However, as the carbon pricing debate in Australia has shown over the past two decades, achieving this can be difficult. Thirdly, including these external costs in the analysis can cloud the fact that, in many cases, DE is lower cost *even if* these external costs are excluded from the analysis.

For these reasons, in the analysis for this thesis, I have deliberately *excluded* environmental and social costs except where explicitly stated. This does not mean that I think they should not be included. (My view is that external costs should be considered.) However, as the prevailing policy paradigm in Australia is that external cost of electricity supply should be dealt with outside the regulatory structure, I have adopted this approach.

7.3.4 Public participation and accountability

Public participation means engaging members of the public in the decision-making about a given issue or institution. In this context, it may include engaging with, listening to and responding to the views and concerns of community members in the process of designing, monitoring, regulating and governing the electricity system. Public accountability means reporting back to the public and stakeholders on performance, particularly against organisational objectives, and on matters of public interest. This can involve gathering and publishing information and other evidence to show how and whether public commitments and expectations are being met, and ensuring that those with a duty to serve the public interest report on their performance of this duty.

For the electricity sector, there are logical, ethical and practical reasons for ensuring that public participation and public accountability are built into the decision-making structure. From a logical perspective, if the purpose of the electricity sector is to serve the interests of consumers, and if consumers are the best judge of their own interests, then it follows that the consumers themselves should participate in defining what their interests and preferences are.

The electricity sector has significant impacts on the community. From an ethical perspective, these impacts far transcend simple economic impacts associated with the cost and quality of electricity supply, and they relate to questions of equity, health and safety, community welfare and local and large scale environment impacts, including climate change. These issues go beyond the interests of individuals as consumers, so it is appropriate to consult and engage with people as citizens as well as consumers.

From a practical perspective, the electricity sector operates within society and society has a major impact on how the electricity sector operates. To operate successfully, the electricity sector needs to prudently and pragmatically engage with society. Failure to do so is likely to have severe adverse impacts on the operation of the organisation, both financially and in terms of its customer and shareholder relations and its reputation. These impacts can affect the organisation's 'social licence' to operate.

For these reasons, developed democratic nations generally have some form of public participation in decision-making about electricity services. In Australia, the most prevalent of these formal processes are undertaken in public consultation by key market institutions, such as the AER and the AEMC and ad hoc political review processes, such as the Finkel Review, the Warburton review of the Renewable Energy Target, and the current public consultation over the development of the National Energy Guarantee.

While public participation may be common to most modern electricity systems, the character and extent of this participation varies widely. This participation can take many forms, ranging from simply voting in elections for governments to make decisions on behalf of the community, to extensive community consultation and engagement processes on the specific operational or investment decisions of electricity utilities.

Alternatives to a public participation approach include either adopting an autocratic approach that ignores consumers' preferences (which is not tenable in a democratic culture), or adopting a paternalistic approach that defines consumers' interests without meaningfully consulting the consumers themselves. An example of the latter approach is where the consumer is simply considered, from a utilitarian or 'Homo Economicus' perspective, as solely interested in receiving electricity at the lowest cost. In this case, it can be argued that there is no need to engage in public participation, since the interests of consumers are *defined* as limited to receiving safe, and reliable electricity at a low price.

While adopting such a narrow interpretation of consumer interest may seem unlikely, it is very close to the interpretation of consumer interest embodied in Australia's National Energy Objective. The NEO refers to a narrowly defined consumers' interest, including mainly technical parameters in, 'price, quality, safety, reliability and security of supply of electricity'. As noted in Section 7.3.1, the NEO excludes 'cost' or 'bills', 'fairness' and 'environmental impact'.

However, *in practice*, the rule-making body, the AEMC, does routinely engage in public consultation when considering rule changes. Examples of consultation include seeking public comment on issues papers and draft rulings. Other factors such as 'fairness' and 'environmental impact' do impact on the NEM via other policy mechanisms specified in policy and legislation outside of the NEM. Similarly, the regulator that applies the rules, the AER, generally engages in detailed public consultation in making its determinations and decisions.

Within LCP, public participation is intended to be closer to the more thorough and engaged end of the spectrum. This is a necessary implication of LCP, as a key component of LCP is 'planning', and the public is intended to play a key role in the developing the plan. In the tradition of LCP, this public participation ranges from comment and feedback on draft plans, goals and proposed options, to detailed stakeholder collaborative processes that may involve numerous face-to-face roundtable discussions over many months.

The practical value of public participation in utility planning is illustrated in Table 7-4, which summarises stakeholder assessment of a range of planning processes. These data suggest an association between public participation becoming more common and more positive pubic assessments of the processes.

Table 7-4 Outcomes of public participation in utility planning processes

Assessment	Mostly Positive	Mixed/Indeterminate	Mostly Negative
pre-1970	1	0	2
1970-1972	7	2	1
1973-1975	9	2	1
1976-1978	9	4	4
1979-1981	15	1	0

(Ducsik, 1986, p. 106) The figures represent the number of cases where public participation played a prominent role in a utility planning process.)

The corollary to the public participation in LCP is accountability. Given that the primary purpose of a least cost plan is to meet customers' energy needs and preferences at the least cost, it is essential that performance against the plan is monitored and publicly reported.

While accountability is important for all electricity systems, there are two reasons why accountability is particularly important in the context of LCP. Firstly, as one of the claims made about LCP is that it meets public needs better by involving customers in setting objectives and plans, it is essential to have effective accountability and reporting in order to substantiate such claims. Secondly, one of the means by which LCP delivers lower costs outcomes is by accessing lower-cost forms of DE, such as energy efficiency and peak load management. Such DE options are innately harder to measure and verify than simply metering electricity supply. Hence, there is a greater need to ensure transparent reporting of the impacts and costs of such resources.

7.4 Critiques of least cost planning. What's not to like?

Given that the principles of LCP outlined are essentially aimed at identifying the needs of consumers and meeting them at lowest cost, it raises the question of why LCP has not been embraced more widely in Australia and elsewhere. Of course, this question applies not just to electricity but to all public infrastructure industries, such as public transport, natural gas, water and sewerage. This issue is highlighted in the following note in relation to urban transportation:

> This idea is as old as formal writings about policy analysis. It is hard to disagree with the idea that the nation and metropolitan areas should make intelligent

> decisions about transportation investments; that intelligent decisions require good information and analysis; and that good analysis means, fundamentally, showing all the costs and benefits of alternative programs and projects to the extent that the the data allow so that the program with the greatest net benefits can be identified and chosen (Parsons Brinckerhoff/ECONorthwest, 1995, p. 1-3).

The answer to why LCP has been neglected in the electricity sector may lie, at least in part, in the criticisms that have been levelled against LCP. These criticisms can be grouped into four broad themes:

- LCP is wrong in principle: Consumer demand is not the business of utilities or government.
- LCP is wrong in principle: Market mechanisms will deliver more efficient outcomes.
- LCP is okay in principle, but bad in practice: LCP understates costs and overstates benefits
- LCP is okay in practice, but other mechanisms are better: Utilities are innately inefficient, and other policy instruments are more efficient.

The following discussion addresses each of these critiques of LCP.

7.4.1 LCP is wrong in principle; consumers are responsible for their own demand

The first and most fundamental critique of LCP (and in particular, DM) is to reject the idea of utilities engaging with DER at all. From this perspective, consumers are the best judges of their own welfare and how to use their own energy, and utilities should simply focus on providing energy at an efficient price.

As Mathew Hoffman writes,

> D[S]M is premised on the notion that **the self-interest of individuals is in conflict with their behavior**: Despite the availability of numerous cost-effective energy efficiency investments, consumers have failed to adopt them.
>
> DSM theory classifies this apparent paradox as a species of "market failure." In this view, the market imperfectly disseminates information about the profitability of energy efficiency investments. However, this paradox may result from

> overestimation of the benefits of energy efficiency investments. In particular, DSM overestimates the benefits of energy efficiency investments by:
>
> - only comparing investment options to the exclusion of other relevant choices faced by energy consumers;
> - neglecting the non-monetary cost components of investments, including transaction costs, measurement and evaluation costs, the risks and uncertainties associated with the investment, its quality of service, and others which often exceed the investment price of the asset significantly; and
> - ignoring the fact that true costs and benefits cannot be measured, since they are subjectively experienced by individuals and therefore cannot be discerned by external observers.
>
> Thus, the perceived market failure may be more accurately attributed to overestimation of the cost-effectiveness of energy efficiency improvements rather than the failure of energy markets (Hoffman, 1995, Executive Summary, emphasis added).

The primary rebuttal to this critique is that LCP starts with public participation to set goals and an overall approach. If customers are not interested in participating in DM and DER, they can make this preference clear at the outset. Secondly, customers are not obliged to participate in DM. LCP and DM simply give them an additional choice. Thirdly, in the absence of LCP, customers are given little freedom to choose their energy supply infrastructure or pricing structures. LCP gives customers more choice, not less.

However, there are still valuable cautionary lessons in this critique. Hoffman's criticisms are relevant not just at a theoretical or policy level, but also at the practical level of engaging with consumers to explain why, as discussed at length in Chapter 5, 'the self-interest of individuals is [sometimes] in conflict with their behaviour'. LCP is very different to the traditional electricity supply paradigm. If DM and LCP are poorly communicated, there is a risk that consumers may respond by saying, 'Why is my utility asking me my opinion or trying to change my behaviour? They should just do their job and supply cheap power!'

7.4.2 LCP is wrong in principle; competition is better

A variation on this critique is to accept that there may be a case for efficiency improvement on the demand side, but to advocate a competitive solution rather than a planned or administered one. At the extreme of this critique, LCP can be seen as a means of utilities pursuing their own interests at the expense of their customers. For example, Mathew Hoffman contends,

> DSM is flawed both in theory and practice. Its theoretical foundation rests on the discredited theories of central economic planning, which presume that governmental and quasi-governmental institutions have the knowledge and incentives to economize on behalf of individuals.
>
> DSM's success can be effectively explained with a public choice model that understands it as a "racket," or a scheme to enable rent-seeking on the part of special interests. It is largely opposed by commercial and industrial ratepayers, which seek to reduce its cross-subsidization effects and clear the way for competitive electricity markets. The outcome of that struggle will ultimately determine the fate of DSM, as well as the nature of the electricity industry in the United States (Hoffman 1995).

This critique overlooks the natural monopoly characteristics of parts of the electricity supply system, which mean that even the traditional supply-side model is dependent on central planning to some extent, particularly in relation to electricity networks. As Roger Sant (1979) outlined in his seminal paper, least cost strategies should lead to more effective competition, not less competition, as a wider range of technologies are allowed to compete.

On the other hand, this critique also offers a valuable caution. If LCP is applied by a monopoly utility, be it a network business (as is the case in much of the Australian NEM) or a vertically integrated utility (as is the case in many parts of the US), then there does need to be some alternative to the discipline of the market to ensure efficient DM expenditure decisions are made. Typically, this is done through economic regulation, as in the case of a traditional supply-side industry structure. However, this means that the economic regulator must have sufficient expertise and resources to ensure that the LCP does actually approach an efficient least cost outcome.

This also highlights the importance of transparent performance reporting and public accountability.

7.4.3 LCP is okay in principle, but bad in practice:

This leads us to the next critique of LCP- that even if LCP is a good idea in practice, it is open to abuse in practice. Eto et al, have summarise this critique as follows:

> As utility spending on DSM increased in the early 1990s, critics began to express their concerns that DSM programs were not cost effective so utility spending on DSM was contrary to the interests of ratepayers (Joskow and Marron 1992). Critics argued that the full costs of DSM were not being accounted for because many utilities did not include the portion of costs paid by program participants who received energy-saving technologies and because utilities did not include many administrative costs in calculating the total cost of DSM programs. DSM program savings were said to be inflated because they were based on engineering assumptions that were not borne out in the field.
>
> More recently however, a systematic review of utility DSM program records has cast doubt on the critics' conclusions. (Eto, 1996, pp. 10-11)

This critique, even if overstated, again provides guidance for ensuring robust and efficient LCP. Even with effective governance and regulation, it is also essential that good processes are applied to measure and verify cost effectiveness, and to report the findings publicly and transparently.

7.4.4 LCP is okay in practice, but other mechanisms are better

Arguably, the most sophisticated critique of LCP accepts the principle and the practical effectiveness of LCP, but challenges its efficiency. Kushler exemplifies this critique by comparing the cost and outcomes of LCP to so-called Energy Efficiency Resource Standards (EERS). These are obligations on utilities to deliver a given volume of energy efficiency to their customers. EERS are similar to energy efficiency certificate trading schemes (also known as 'Energy Efficiency Obligations' (EEOs) or 'White Certificate' schemes outside of the United States). Such schemes apply in many countries, including Australia, such as the NSW Energy Savings Scheme (ESS) and the Victorian Energy Upgrades scheme (formerly Victorian Energy Efficiency Target -VEET) scheme (Nadel et al, 2017).

Kushler's analysis reviews firstly, utility energy efficiency expenditure relative to its revenue and secondly, the volume of annual energy savings relative to its total annual energy sales in US states. It then compares these two factors in the context of whether or not there is LCP and/or an EERS in place. Kushler's data is presented in Table 7-5 and Table 7-6.

Table 7-5 Impact of presence of IRP on energy efficiency spending and savings in USA

	IRP/LCP	IRP/LCP or other long term plans	No IRP/LCP or other long term plans
No of states	28	38	12
$EE Exp/$Revenue	1.64%	1.81%	1.5%
Energy saved/energy sold	0.72%	0.80%	0.48%

(Kushler, 2014)

Kushler finds that energy efficiency expenditure and savings tend to be higher in states with IRP/LCP than in states without IRP/LCP, but 'there is no statistically significant difference in either energy efficiency program spending (1.64% of revenues vs. 1.50%) or savings (0.72% of sales vs. 0.48%).' On the other hand, when the application of Energy Efficiency Resource Standards is considered the differences for states with and without an EERS policy are striking … A very significant difference emerges between these two groups, with EERS states showing over three and a half times as much program spending (2.63% vs. 0.76%) and savings (1.11% vs. 0.30%) as the non-EERS states. These strong results from EERS are present whether or not the state has an IRP/LCP policy (Kushler, 2014).

Table 7-6 Impact of presence of EERS energy efficiency spending and savings in USA

	EERS	No EERS
No of states	26	24
$ EE Expenditure/$ Revenue	2.63%	0.76%
Energy saved/energy sold	1.11%	0.30%

(Source: Kushler, 2014)

Kushler concludes,

> Overall, the inescapable conclusion is that having an EERS is clearly the most effective state policy driving energy efficiency program spending and savings in the U.S. utility sector today. There is little evidence that IRP alone produces meaningful energy efficiency results in the absence of other strong policies. Other supportive policies, such as decoupling and shareholder incentives, appear to be helpful and are associated with modest increases in energy efficiency investments and savings.

> Yet, the most important value of such policies to date may not be their stand-alone effects, but rather, their ability to establish a fair utility business model that encourages utilities to accept and work toward achieving EERS efficiency targets—instead of seeking to block or overturn the EERS policy.
>
> In a time when some state policymakers are becoming skittish about the concept of "mandates," it is worth noting that the use of an EERS to set targets for cost-effective efficiency has been by far the most effective policy for achieving customer energy efficiency savings (Kushler, 2014).

The issue of EERSs, or EEOs, is discussed further in Section 8.6.

7.5 From least cost planning and competition to least cost competition

7.5.1 Pursuing least cost in liberalised electricity markets

The primary objective of least cost planning for electricity is simply to facilitate an optimal mix of electricity demand and supply options to minimise costs to consumers. In the context of a traditional, vertically integrated monopoly electricity supplier, applying LCP is in principle straightforward.

However, as noted in Chapter 1 and Section 8.1, in recent decades Australia's energy policy makers have chosen a different path to pursue lower electricity costs. Since the Industry Commission Competition Inquiry (1991b) and the Hilmer Competition Review (1993), the dominant theme of electricity reform in Australia has been competition.

This focus on competition left little room for the principles or practice of LCP. To a degree, this neglect of LCP was both necessary and appropriate. In a disaggregated, competitive industry structure, coordinated sector-wide 'planning' is not possible. Competitive markets do not have an overarching *plan* for allocating resources, as it is the role of the market to allocate resources.

However, competition reform is widely regarded to have failed to deliver the benefits that were promised (Ison et al, 2011). This failure has cost consumers billions of dollars in avoidable network investment, precipitating a doubling in electricity prices between 2007 and

2014 (see Figure 8-5), and has led to the collapse of the political consensus for effective action on climate change.

It is highly likely that these adverse outcomes could have been avoided with greater attention to least cost principles. There are four ways in which a least cost approach could have assisted:

1. by explicitly considering the *objectives* to be achieved by the electricity sector, including *all relevant costs* and environmental goals, and ensuring timely *accountability* against these goals
2. by highlighting the potential for *all options*, including DM, to deliver lower cost e*nergy services* for consumers
3. by ensuring *public participation* in the monopoly planning role of the electricity network businesses and focusing on the potential for DM (including price reform) to avoid, defer and reduce these costs
4. by moderating the rapid increase in electricity costs, prices and bills, and thereby reducing the public anger that resulted at the time, which to a large degree led to the repeal of the carbon pricing mechanism scheme.

So while at first glance, least cost planning may appear incompatible with competitive electricity markets, many least cost *principles* of can be applied in liberalised electricity markets, both in relation to enhancing competition and in relation to good governance of markets.

As noted above, the concept of 'least cost energy strategy' was *not* first proposed as a form of central planning at all, but rather as a strategy to encourage greater and more efficient competition (Sant et al., 1984) The 'planning' element of the least cost strategy was only added later in order to apply it to the monopoly structure that prevailed in the industry in most of the US states (an in other countries) at the time.

There are two broad approaches to applying least cost principles in a liberalised electricity market, such as Australia's. The first is to apply a form of LCP in the remaining centrally planned regional monopoly (network) components of the industry. This involves applying least cost principles to the distribution and transmission network businesses. The second approach is to apply broader least cost principles in the competitive (generation, retail, etc.) parts of the industry. These two approaches are discussed below.

LCP for centrally planned networks in liberalised markets

A key early step in the liberalisation process in Australia was to separate the potentially competitive generation and retail sectors from the monopoly transmission and distribution network services, which as shown in Figure 7-7, comprise up to half of the cost of electricity supply (AEMC 2017, p. viii). The network businesses remain centrally planned regulated monopolies, and are responsible for most of the billions of dollars invested in the Australian electricity sector each year.

The central planning and procurement of network support (in the form of either decentralised energy options or network augmentation) can be reconciled with competitive generation and retail markets through a competitive procurement process. For such a procurement process to be efficient for decentralised energy options, it is essential for the value of avoided networks to be accurately estimated. The Dynamic Avoided Network Cost Evaluation (DANCE) Model, as applied to the Network Opportunity Maps described in Chapter 3, illustrates how to do this efficiently and how to estimate the potential value of applying decentralised energy in place of network capacity augmentation.

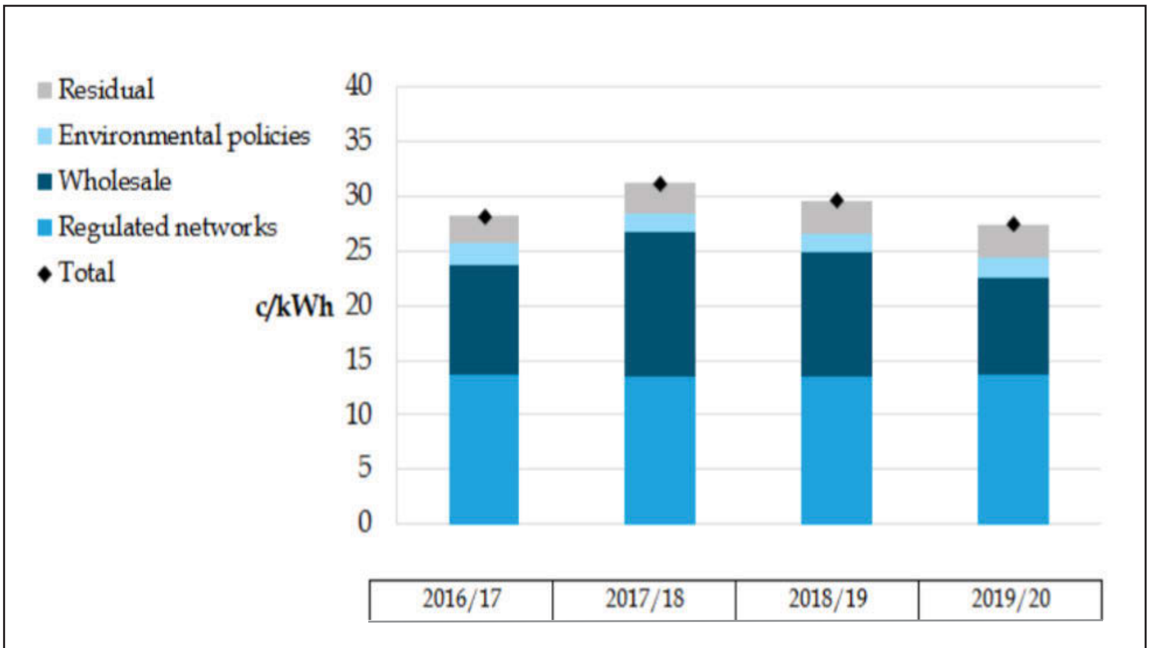

Figure 7-7 Forecast trends in composition of residential retail electricity prices

(AEMC 2017, p. viii)

Following liberalisation of the generation and retail segments LCP could still have been applied to the monopoly network sector, but unfortunately, this was not case. While there were some legislative and regulatory requirements for network businesses to consider cost effective demand-side resources, the NEM did not create an effective framework to encourage or enforce least cost outcomes.

Least cost principles in competitive market segments

The second approach to applying broader least cost principles in the competitive (generation, retail) parts of the electricity system relates to how the electricity sector as a whole is governed. There are several aspects to this. Firstly, even within the competitive retailing and generation segments, the regulators and the government retain explicit regulatory powers and/or implicit political authority which may be exercised should the market manifestly fail to meet community and consumers' expectations[43]. The evaluation tools of LCP can be used by regulators and policy makers for monitoring the efficiency of market operation, even if no formal central planning is undertaken.

Secondly, least cost principles can be applied through competitive market principles of transparency, cost-reflective pricing and competitive procurement in network planning and development.

7.5.2 Principles of least cost competition

With the exception of the reference to 'resource plan', the fundamental principles of LCP can be applied to all electricity industry structures from monopolies to all forms of competitive markets. As noted by Rufolo et al. (1995, p. 7) and in Section 7.3, these LCP principles include:

- explicit consideration of **objectives**;
- explicit consideration and fair treatment of a **wide variety of options, including demand,** supply, transmission and distribution, and pricing alternatives;
- consideration of environmental and other social costs of providing energy services;
- **public participation** in the development of the resource plan;

[43] The community generally expects and industry participants generally recognize, that if the market manifestly fails to meet community and consumers' expectations either in terms of cost or reliability then the regulator or the government will intervene, just as occurred in California following the 2001 energy crisis, and just as the governments of most developed nations have intervened in the financial markets in recent months.

- **analysis of uncertainties** associated with different external factors and resource options.

However, these LCP principles were developed in the context of a traditional centralised planning industry structure, so they sit a little incongruously with the liberalised electricity sector. Indeed, as Rufolo et al. have noted:

> … while the body of literature on least cost planning is extensive, its usefulness is primarily to suggest a conceptual framework for analysis, and to offer a body of experience for comparison, rather than to provide a 'cookbook' for analysis" (p. 11)

In order to apply least cost principles to the liberalised industry structure, it is possible to recast (and reorder) them in a more pro-competitive manner, as follows (*the original LCP principles are retained in **blue italics***):

Least cost competition principles

1) **Clear and appropriate purpose:**

   - ***Explicit consideration of objectives.*** (As per LCP.) While serving the interests of consumers, citizens and/or the community is the most obvious objective for the electricity sector, there are crucial questions that need to be addressed. These include: *Who decides what constitutes the public interest? Which is the pre-eminent public interest: consumer interests, citizen interests or community interests?*

2) **Public participation and accountability:**

   - ***Public participation in the development of the ~~resource plan~~*** market objectives, rules, culture and performance metrics. The market objectives can only be legitimate if it they are established through legitimate processes.

   - **Accountability to consumers and community** – Regular monitoring and public reporting of performance and outcomes relative to the explicit objectives. Accountability also relates to supporting rules and a culture of least cost among industry managers and participants (Littlechild and Mountain, 2015).

3) **Cost-reflective *pricing:***

- An efficient market depends on prices that reflect the true cost of supply. Because of the importance of efficient pricing to effective competition, it is appropriate that cost-reflective pricing is included as a principle of least cost competition in in its own right.

4) **Competition among all feasible options:**

- *Explicit consideration and fair treatment of a wide variety of options, including options which affect demand, supply, transmission and distribution, and pricing alternatives.* This principle is the same as for least cost planning, but its application is different in the context of least cost competition. In least cost planning, it is the responsibility of the planner to ensure all feasible options are fairly considered. In least cost *competition*, it is up to the market to propose and select the least cost, most efficient option. However, the market can only do this if the market rules and other industry systems permit all options, and in particular decentralised energy, to compete equally.

5) **Competition based on all relevant costs:**

- ***Consideration of*** all relevant ***environmental and other social costs of providing energy services****.* Again, the essence of this principle is the same as for least cost planning, but its application is different for least cost competition. For least cost planning, it is up to the planner to consider these costs; for least cost competition it is essential that these costs are built into the industry and market structure.

Principle 5, regarding all relevant costs, clearly links to Principle 3, regarding cost-reflective pricing. It also links to Principle 1 about purpose, and Principle 2 regarding public participation, since the decision about which costs are relevant and need to be included must be defined through a legitimate process.

Principle 5 also incorporates the LCP principle of ***analysis of uncertainties associated with different external factors and resource options.*** Whereas in LCP, uncertainty is supposed to be explicitly considered by the planner, in the context of competitive markets, providers and consumers will explicitly or implicitly incorporate risk and uncertainty into their investment and purchase decisions.

In terms of public accountability, it is also important to recognise all relevant costs associated with competition (and administration) and to seek an optimal mix to minimise costs. This would include marketing costs on the part of electricity suppliers and search and disruption (and annoyance) costs on the part of consumers in interacting with the market.

The evolution of these principles in the different market contexts is compared in Table 7-7.

Illustrating least cost competition

There are many ways of graphically representing the electricity system. Such representations all seek to simplify the complexity of the system while highlighting the most important elements. Figure 7-8, Figure 7-9 and Figure 7-10 present different perspectives on the electricity system, including traditional utility planning, least cost planning and a technical/market perspective respectively. This reflects different priorities, emphases and, from a Kuhn perspective, paradigms for each. Consequently, they are not directly comparable. Nonetheless, they offer an insight into what aspects of the system are important to key stakeholders.

Table 7-7 Comparing least cost principles in different electricity market paradigms

	Current Australian 'competitive market'	Least cost planning	Least cost competition
1. Clear and appropriate purpose	'Static' objective: National Electricity Objective – NEO (focus on price, quality, safety, reliability, and security of supply) Social and environment issues to be addressed by government.	Least cost, incl. social and environment costs, (subject to quality, safety, reliability, and security standards)	Focus on least cost (subject to government & community requirements re: social and environmental constraints, quality, safety, reliability, and security standards.) Community consultation and accountability on objectives and requirements.
2a. Public participation	Via regulatory determinations and rule changes	Participation of participants via planning process and consideration of options.	Accountability on inclusion and exclusion of participants. Reporting on costs as part of accountability.
2b. Public Accountability	In principle, limited. In practice, subject to a wide range of overlapping, and varying reviews, reports, rule changes, etc.	Public participation in the development and delivery of the resource plan.	Regular & consistent reporting against all elements of market objective is crucial. element
3. Cost-reflective pricing	Pricing left to suppliers. Participants encouraged to adopt cost-reflective prices.	Considered as one of the LCP options	Accountability on efficient pricing essential to effective competition
4. Competition of all viable options	Focus on supply side. Demand side generally regarded as up to the customer	Considers all supply and demand-side options considered in planning.	All supply- and demand-side options facilitated to compete. Accountability on inclusion of all.
5. Competition on all relevant costs	Costs not directly relevant – focus on price. Use market pressures to reduce direct costs. Social and environmental costs treated as policy issue, external to the market.	Considers all costs (can be arbitrary and complex)	Direct costs plus indirect costs included via policy. Accountability on inclusion of all relevant costs. Reporting on costs as part of accountability.

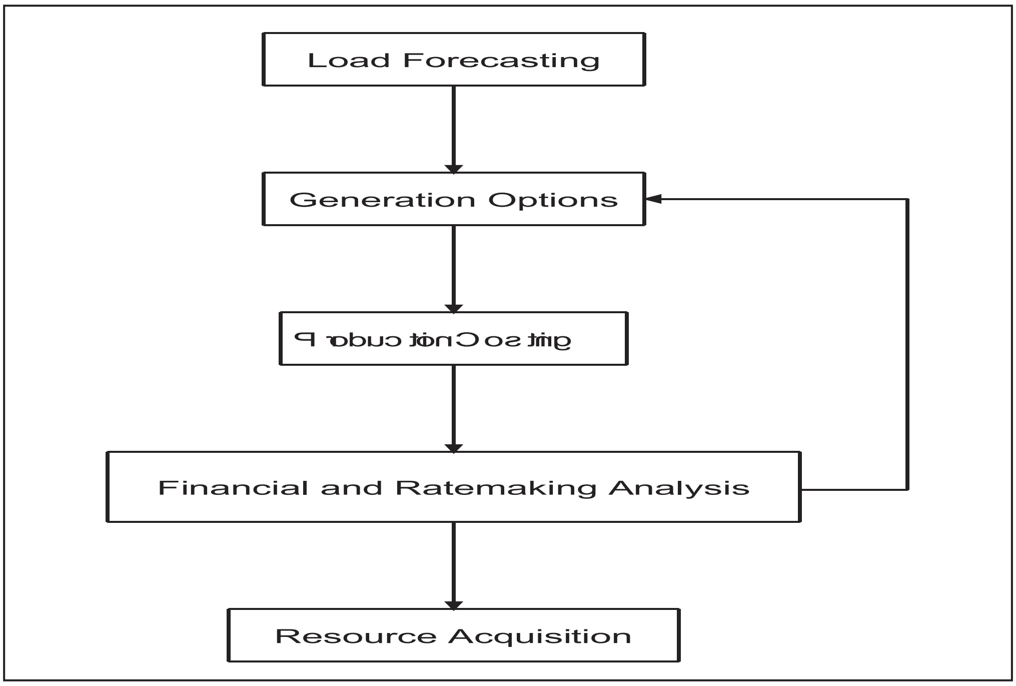

Figure 7-8 Traditional utility planning process

(Eto, 1990, p.970, cited in Mills, 1997)

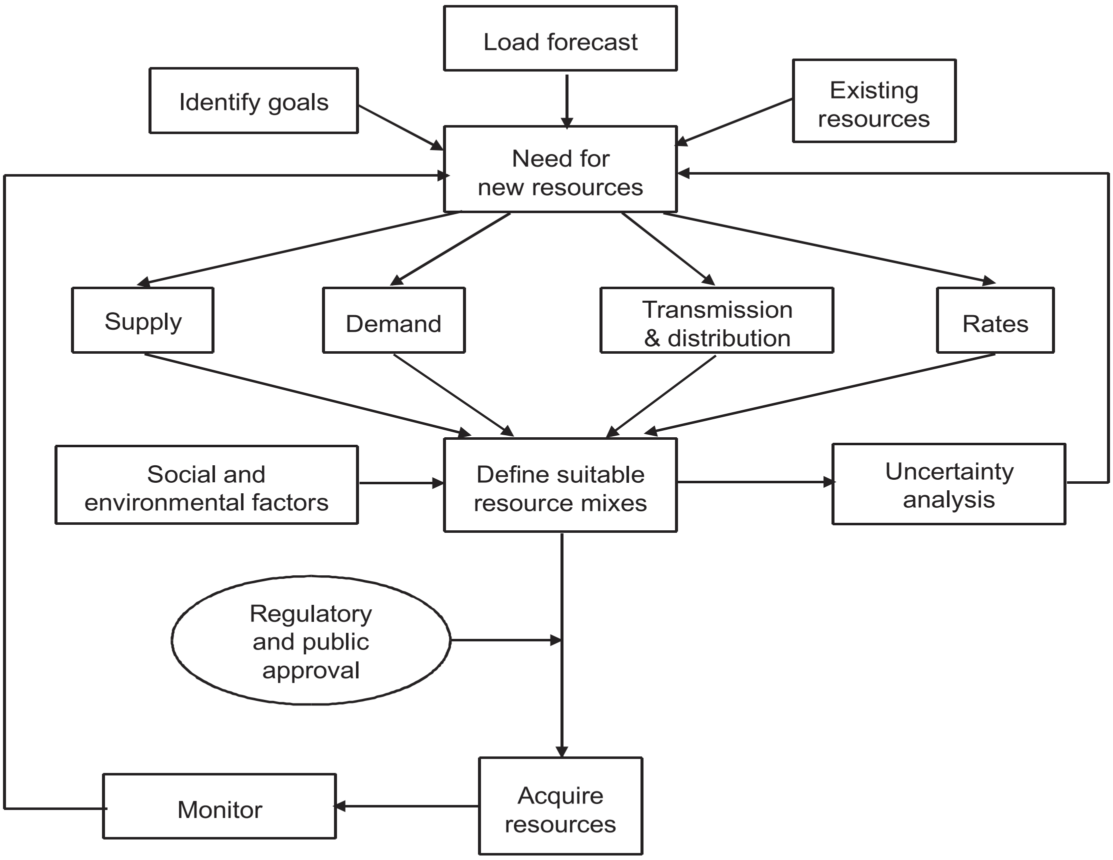

Figure 7-9 Least cost utility planning process

(Electrical World, 1989, p.19, cited in Mills 1997)

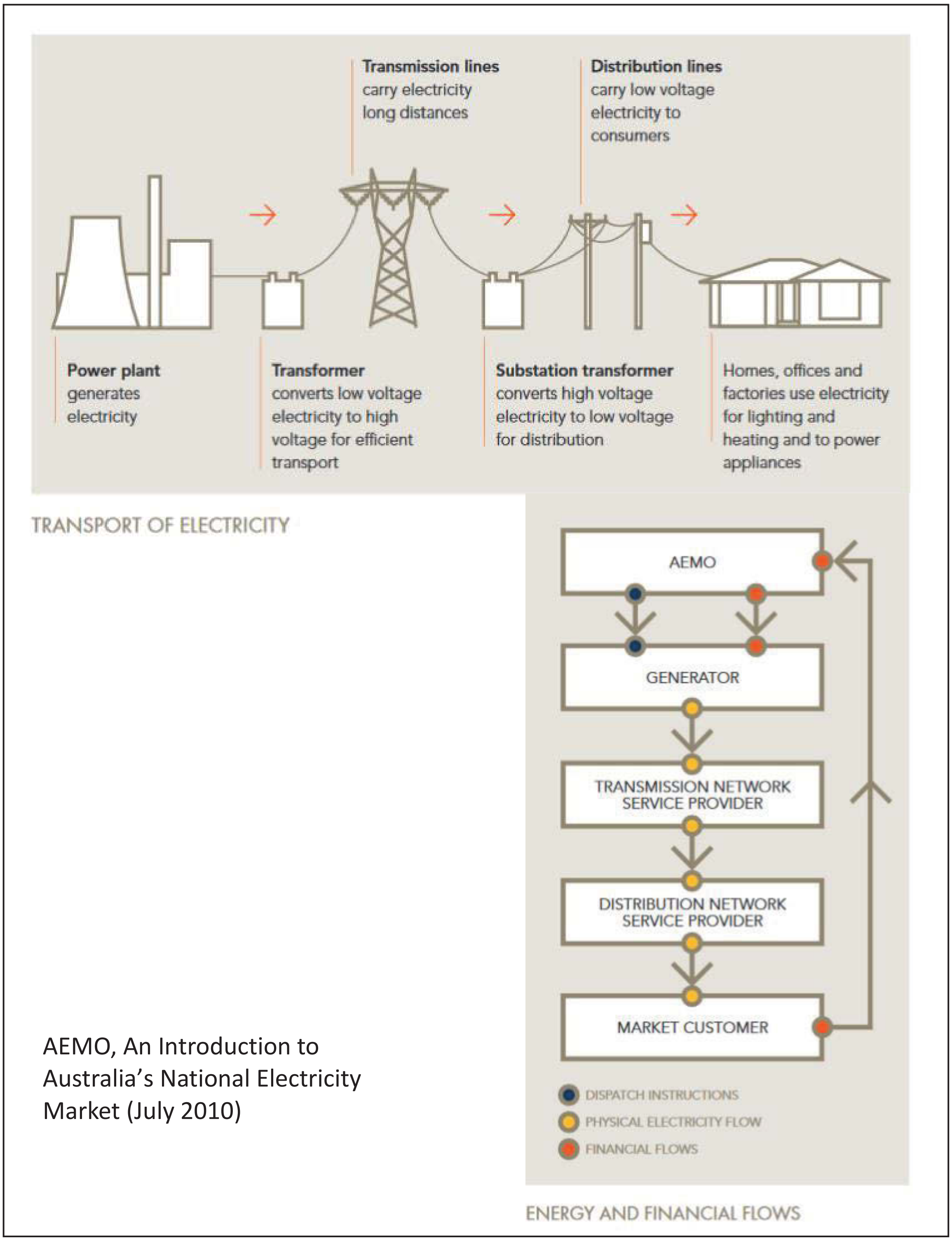

Figure 7-10 The Australian National Electricity Market – physical and financial flows (AEMO, 2010e)

In order to provide a common framework for comparison in this thesis, I developed the generic electricity sector schema in Figure 7-11. Figure 7-12 builds on this framework to illustrate a least cost competition approach. The five principles of least cost competition are included with the key functions common to all segments of the electricity system: governance, forecasting, risk analysis, procurement and service delivery. These functions are colour coded according to whether they are competitive or administered processes. This schema will be used to illustrate the application of least cost competition in each market segment in Chapter 8.

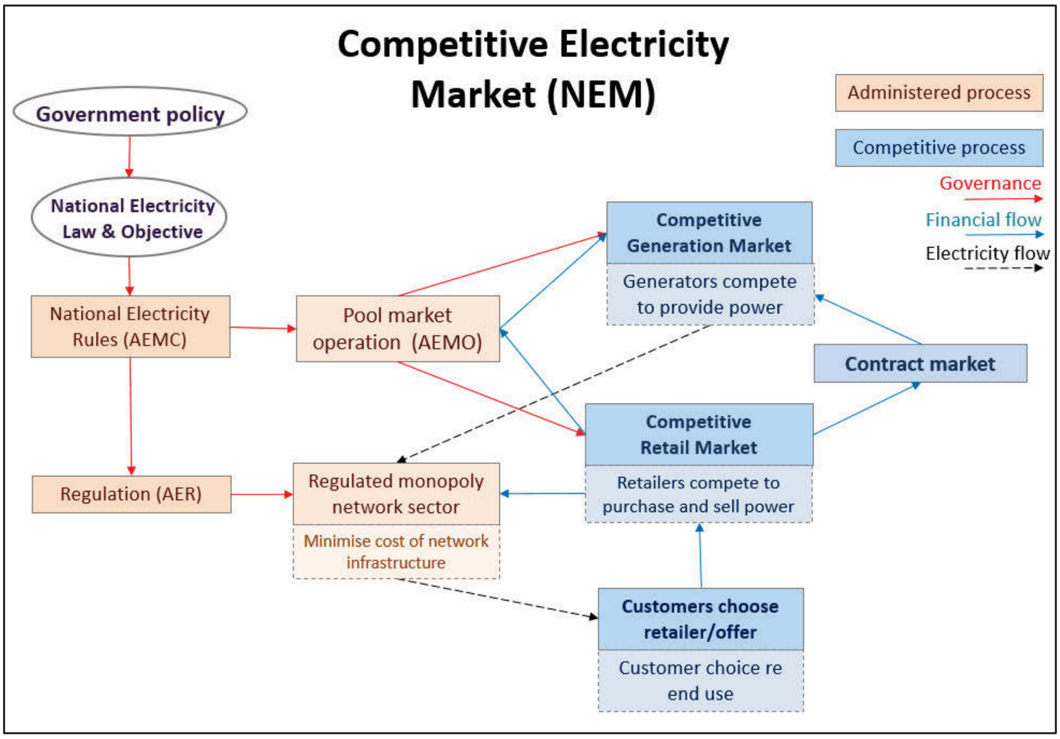

Figure 7-11 Framework schema: Competitive Electricity Market (NEM)

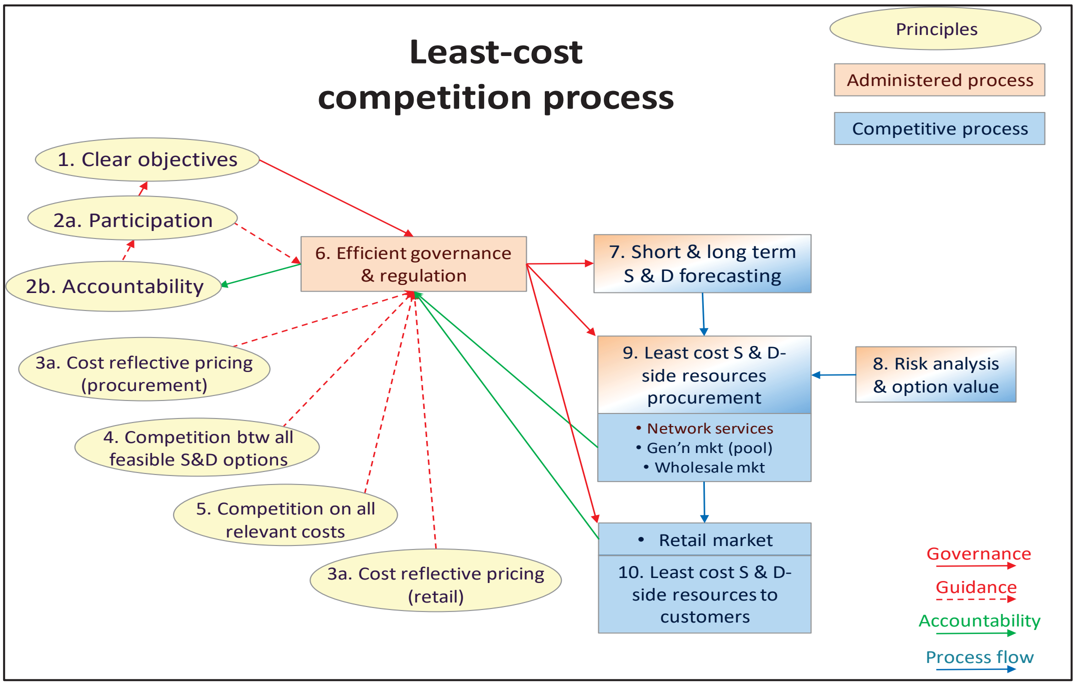

Figure 7-12 Generic least cost competition process

Chapter 8. Applying Least Cost Competition in Australia

'This time it was right, it would work, and no one would have to get nailed to anything.'

- Douglas Adams, *The Hitchhiker's Guide to the Galaxy*, 1979

8.1 A brief history: electricity, competition and least cost principles in Australia

As the name suggests, Least Cost Planning (LCP) is a form of planning. With the recent emphasis on using competitive markets to make resource allocation decisions in the electricity generation and retailing sectors, the role of (LCP) has been neglected in Australia and overseas (Swisher et al, 1997, p. vii). This section considers the background to emergence of electricity competition and LCP in Australia.

8.1.1 History of competition reform in electricity in Australia

As in other parts of the world, electricity supply in Australia initially developed through a combination of private companies and government support for, or grant of, exclusive service areas for public lighting. These private and public enterprises were generally established as local monopolies, often under the aegis of local government, reflecting the public good aspects of street lighting.

The role of government in providing electricity in Australia as an 'essential' monopoly service strengthened in the first half of the 20th century, with the establishment of large-scale, state government-owned electricity commissions (such as the Hydro-Electric Commission of Tasmania in 1914[44]) to facilitate the rapid development of low-cost generation and subsequently high voltage transmission networks.

The dominant role of state governments in owning, managing and administering electricity supply as monopoly providers continued until the late 1980s. At this time, there was a strong reform agenda in Australia around competition and privatisation. The drivers for this reform were manifold, but many aspects related to what has been described as a 'neoliberal' reform

[44] This was followed by the State Electricity Commission of Victoria in 1918, the State Electricity Commission of Queensland in 1938, the State Electricity Commission of Western Australia in 1945, the Electricity Trust of South Australia in 1946, and the Electricity Commission of NSW in 1950.

agenda[45]: that is, increased competition, privatisation and a reduced role for the state. This paradigm shift related to the end of the post-war boom and the collapse of the Keynesian consensus about the guiding role of the state in economic affairs, and the rise of what in Australia was called 'economic rationalism', but what might more accurately be called 'market fundamentalism'. This trend in was exemplified by the Austrian and Chicago schools of economic thought, Monetarist economic theory and the political and economy policies of the Thatcher and Reagan governments. It is not the purpose of this thesis to explain the emergence of 'economic rationalism' or neoliberalism in Australia, but these trends played a key role under the Hawke-Keating Governments (1983-1996) in the development of competition policy in Australia, particularly in relation to the electricity sector.

In particular, a key milestone in the competitive reform of the electricity sector was the Industry Commission inquiry initiated by former Prime Minister Paul Keating when he was Treasurer in 1991. The Australian Energy Market Commission (AEMC) recognized this watershed event as follows:

> The formal process to develop the NEM began in 1991 with a decision by the Council of Australian Governments (COAG) to establish a National Grid Management Council to coordinate the planning, operation and development of a competitive electricity market. COAG took this decision in response to a report tabled in 1991 by the Industry Commission which found that potentially significant increases in Australia's Gross Domestic Product (GDP) could be realised by:
>
> • a restructuring of the electricity supply industry with the vertical separation of generation and retail from the natural monopoly elements of transmission and distribution;
>
> • the introduction of competition into generation and retail by providing access to the transmission and distribution systems on a non-discriminatory basis;
>
> • progressively selling publicly owned electricity generation, transmission and distribution assets to the private sector; and

---

[45] The lineage of the "neoliberal" agenda can be traced back to the emergence of classical Liberalism of the early 19th century UK, including such philosophers and economic and social reformers as Jeremy Bentham and John Stuart Mill. However, the primary focus of modern "neoliberalism" is overwhelmingly on the economic liberalism of free markets, rather than the social liberalism of equality of social opportunity and social justice.

• the enhancement and extension of the interconnected systems of NSW, ACT, Victoria and South Australia to eventually include, when economically viable, the power systems of Queensland and Tasmania (AEMC, 2016a).

The competitive National Electricity Market (NEM) formally began in December 1998. The introduction of the NEM has been lauded by some as a case of successful microeconomic reform (AEMC KPMG 2013), but the evidence of its success is far from clear (see Ison et al 2011, Energy Security Board 2017).

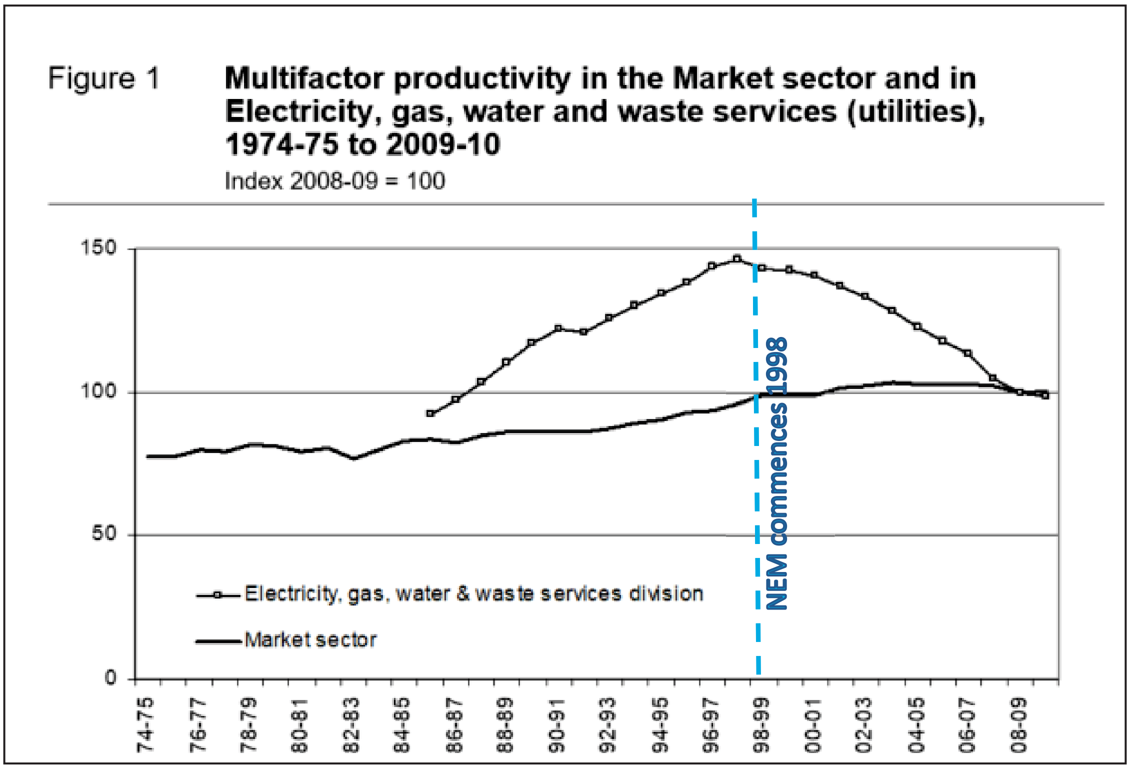

Figure 8-1 Multifactor productivity in the electricity sector in Australia
(Topp & Kulys 2012)

As shown in Figure 8.1, total factor productivity for the electricity, gas, and water and waste services division (of which electricity is the largest part) declined sharply beginning in 1998 when the NEM commenced operation, until at least 2008–09. Figure 8-2 and Figure 8-3 indicate that this decline in total factor productivity (TFP) continued after this time, at least in the transmission and distribution sector.

Figures 8-4 and 8-5 show that wholesale electricity prices and residential retail prices have also trended upward in the period since the commencement of the NEM.

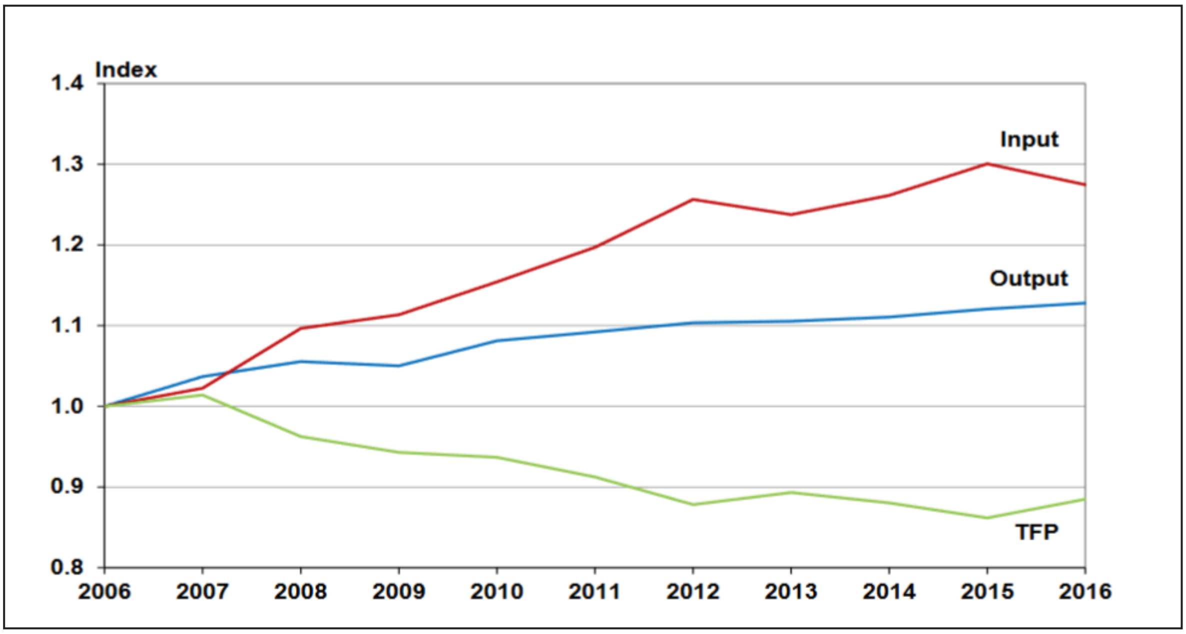

Figure 8-2 NEM distribution network productivity indices (2006-2016)

(AER 2017b, Fig. 11)

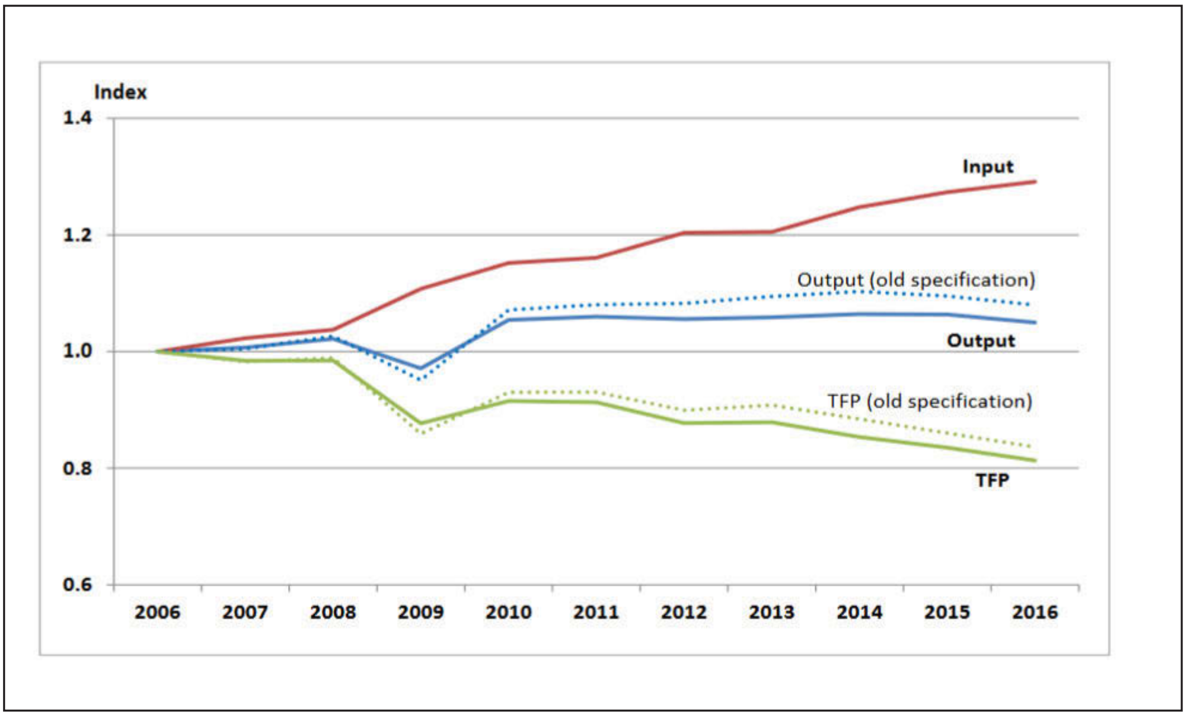

Figure 8-3 NEM transmission network productivity indices (2006-2016)

(AER 2017b, Fig 3)

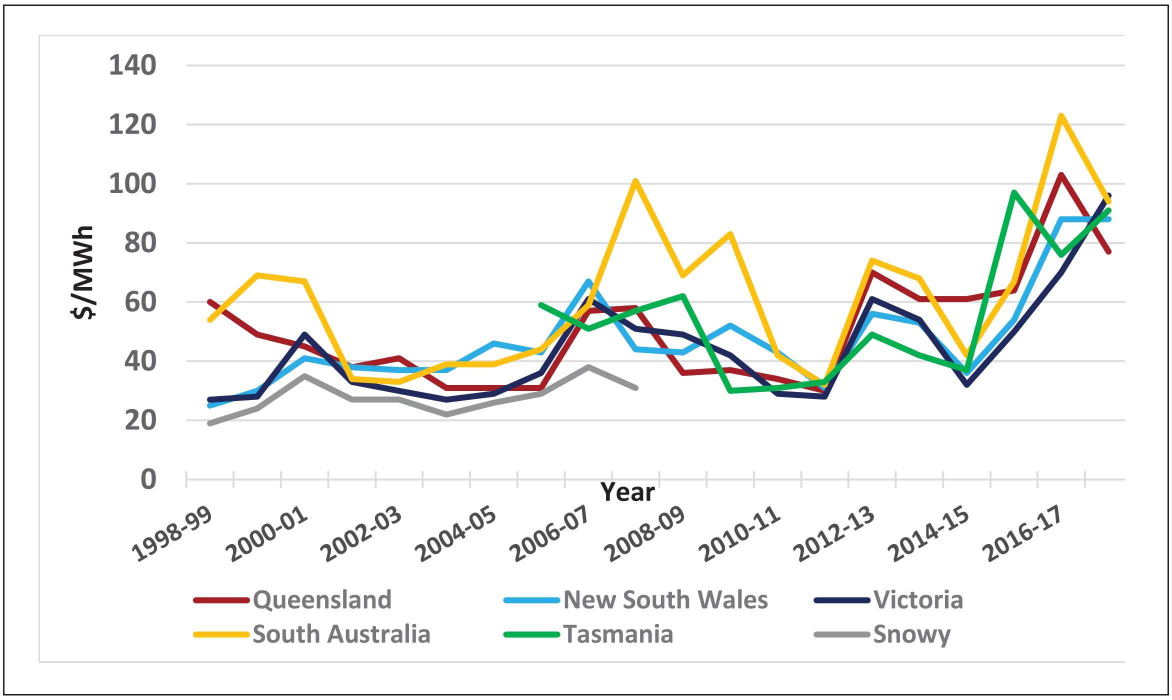

Figure 8-4 Average annual pool price by NEM region (1998-2017)

(AER, 2018)

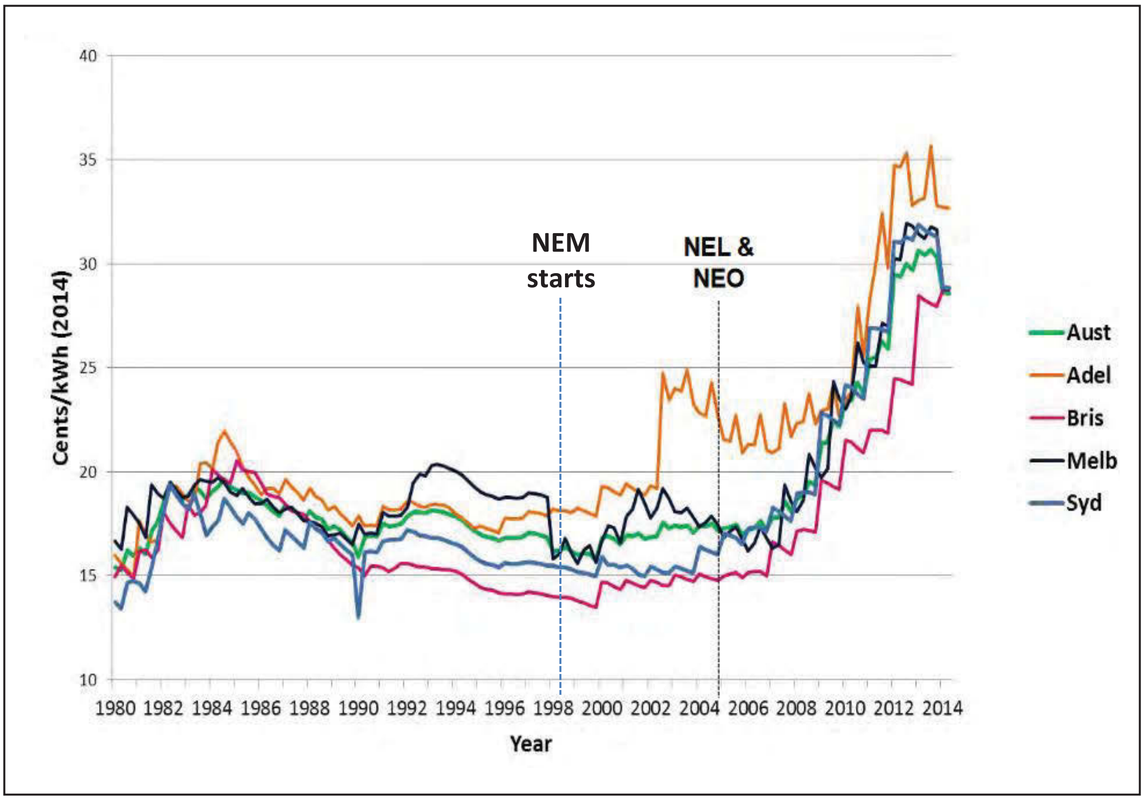

Figure 8-5 Real residential electricity prices (1980-2014) - Australia and key cities

(Dunstan, 2015b, p.6)

A clear implication and key conclusion of this thesis is that if a least cost approach had been adopted for the national electricity market since its inception, then much better outcomes could have been delivered for Australian energy consumers and the Australian economy and community.

8.1.2 History of least cost planning in Australia's electricity sector

In Australia, as in many other countries, the failure of the electricity sector to deliver economically efficient, least cost outcomes has been widely recognised for decades (McDonell 1986, Lovins 1990, Industry Commission 1991b, IPART 2002, Australian Government 2002, Australian Government 2004, Independent Panel 2004, Queensland Department of Employment, Economic Development and Innovation 2011, AEMC 2012, Finkel 2017).

The LCP principle of meeting consumers' electricity needs at the lowest cost seems to be an uncontroversial objective. However, minimising costs and optimally balancing supply and demand resources has, to date, not been a primary objective of electricity policy in Australia in practice or in law.

A likely cause for the relatively low level of adoption of LCP in Australia compared to the US is the difference in circumstances of the electricity sector. Many of the most serious and controversial impacts of electricity generation, which were powerful motivators of the adoption of LCP in the US, were either less severe or non-existent in Australia. For example, Australia did not have significant reliance on oil-fired power stations dependent on expensive foreign oil. Australia did not have highly contentious nuclear power. Australia has had much less severe acid rain problems and Australia has few viable undeveloped hydroelectric resources[46]. It was only with the advent of climate change as a major issue in Australia in the late 1980s that significant and sustained advocacy emerged for alternatives to centralised (mainly coal-fired) electricity generation and supply.

While LCP has never been fully adopted in Australia, there have been several instances where least cost principles have been applied to varying degrees. The following programs and

[46] The Snowy Mountains hydroelectric system had been essentially completed by 1974 (Bergman 1999). There were two significant hydroelectric proposals in Tasmania in the 1970s and 1980s, the Lake Pedder and the Gordon-below-Franklin dams, but the debate about the Lake Pedder Dam project was largely contained to Tasmania, while the Gordon-below-Franklin Dam was blocked in 1983 after an unprecedented national grassroots protest campaign.

initiatives provide useful precedents to illustrate the capacity for Australian governments and utilities to run successful cost-effective DM programs.

Energy Authority of New South Wales (mid 1980's)

The Energy Authority of New South Wales (EANSW) was established in November 1976 by the Wran Labor Government and abolished in July 1987 by the Unsworth Labor Government (National Library, n.d.).

The first major effort to apply the least cost planning principles in Australia was by the NSW Labor Government after Peter Cox was appointed Minister for Mineral Resources and Energy in 1984 (Stephens, 2008). At this time, the oil crises of 1973 and 1979 were a fresh memory, there was rapid growth in demand for electricity and electricity supply interruptions and reliability problems were emerging. The Energy Authority of New South Wales established a wide range of innovative energy conservation programs, including appliance efficiency labelling, minimum energy performance standards and industry energy efficiency advisory programs.

NSW McDonell Inquiry (1985-86)

In the early to mid-1980's, the Electricity Commission of New South Wales was committed to a massive and contentious program of building four large coal-fired power stations, at a cost of about $12 billion. In order to address the rising controversy, in 1985, Minister Cox and the NSW Government established a Commission of Inquiry into Electricity Generation Planning in New South Wales chaired by Gavan McDonell (McDonell, 1986).

The Inquiry made several recommendations that reflected LCP principles. Firstly, it recommended that four proposed new power stations should be abandoned in favour of more efficient operation of existing power stations and greater energy conservation and demand management. It also noted 'the need for systematic, comprehensive and well-articulated planning, which will be necessary for the least cost development required to ensure NSW's future position as an economic supplier of electricity' with a much greater degree of public participation and accountability (McDonell 1985, p. ii).

The Inquiry found that existing power stations were operating very inefficiently, and that if the sector were reformed there would likely be sufficient generation capacity for a further 20 years. This conclusion was borne out by subsequent events, as there was ultimately no need for the four additional proposed power stations. The Inquiry also recommended improved coordination with the adjoining states' systems and the interconnection in eastern Australia of regional power markets. This recommendation was a precursor to the establishment of the National Electricity Market.

If all of the Inquiry's recommendations had been adhered to, then Australia could have had the benefits of a coordinated National Electricity Market and the benefits of a least cost planning approach.

National Grid Protocol (1992)

Following the Industry Commission inquiry into Energy Generation and Distribution (Industry Commission, 1991), there was a strong push towards competitive reform of the electricity sector. This process was initially guided by the National Grid Management Council and its direction was summarised in the 1992 National Grid Protocol, which stated:

> Demand Management and renewable energy options are intended to have equal opportunity alongside conventional supply side options to satisfy future requirements. Indeed, such options may have advantages in meeting short lead-time requirements... (National Grid Management Council, 1992, p. iii)

However, in practice, DM has not been allowed an equal opportunity to satisfy consumer electricity needs.

Victorian Demand Management Action Plan (1989-1994)

The ground-breaking Victorian Demand Management Action Plan (DMAP) was established in 1990 by the State Electricity Commission of Victoria to investigate strategies to moderate demand for electricity. This remains the largest and most comprehensive DM program undertaken in Australia to date. The Demand Management Action Plan identified and demonstrated many cost-effective options for consumers to save energy. The DMAP was deliberately developed via a Demand Management Development Project (DMDP) using LCP methods. One of the key consultation documents was titled 'Integrated Resource Planning' and it used IRP/LCP methods to identify priority actions for implementation (SECV/DITR, 1989a). Between 1990 and 1993, $27.5 million was expended, delivering an estimated net economic benefit of $44.5 million (Electricity Services Victoria, 1994).

The DMAP was wound up following the election of the Victorian Kennett Liberal Government in October 1992.

NSW SEDA 1996–2004

In a similar manner to the Victorian Kennett Liberal Government which came to power in October 1992 with an agenda of competitive reform and privatisation, so too the NSW Carr Labor Government, when elected in 1995, aimed to facilitate competitive reform and privatisation of the NSW electricity sector. In order to pass legislation for the first step in this reform, the NSW Government needed to win the support of the unaligned cross bench members of parliament in the NSW upper house. The $45 million Sustainable Energy Fund was established as part of a legislative deal with these members of parliament. The Sustainable Energy Development Authority (SEDA) was subsequently established to administer this fund.

Under the leadership of dynamic American Chief Executive Cathy Zoi, SEDA established a wide range of renewable energy and energy efficiency programs. These program included Energy Smart Homes, which establish energy efficiency standards for new home construction, Energy Smart Business, which assisted industry to identify and implement energy efficiency improvements and the Australian Building Greenhouse Rating Scheme, which rated the energy efficiency of commercial office buildings. SEDA reported delivering through its programs “lifetime energy savings for the NSW community worth over $1.3 billion; and reducing greenhouse gases by over 35 million tonnes of carbon dioxide” (SEDA 2004, p. 5).

The Government’s plans for privatising the electricity sector were thwarted and SEDA was absorbed into the NSW Department of Energy Utilities and Sustainability in 2004 and many of its program were abolished (SEDA 2004).

NSW Energy Savings Fund NSW (DM Fund, 2004-2007)

Following the closure of SEDA, the NSW Energy Savings Fund was established in 2005 with a DM focus to provide $40 million per annum over five years (Sydney Morning Herald, 2005) in incentives to ‘encourage innovative and practical investment in measures such as energy efficiency, peak load management and localised generation’ (NSW Government, 2015). In its first two years of operation, $29 million was allocated, delivering estimated savings of 189,000 MWh per annum at a cost of $15 per MWh, and 46,560 kW per annum of demand reduction at an estimated cost of $61/kW per annum (NSW Department of Environment and Climate

Change, 2008).[47] This was a relatively low cost for demand reduction, particularly given that peak demand reduction was not the primary focus of the Energy Savings Fund.

In 2007, the operation of the Energy Savings Fund was merged into the NSW Climate Change Fund (DECC, 2008b, p. ii) and the focus on DM was reduced. In 2010, the Fund was largely redirected to pay for a large budget blowout in the NSW solar feed in tariff (NSW Office of Environment and Heritage, 2010, p. 34).

South Australian DM Fund (2005-2010)

In 2005, the Essential Services Commission of South Australia (ESCOSA), the state's electricity regulator, developed a demand management framework based on a cost–benefit analysis that outlined power factor correction, standby generation, residential direct load control and aggregation as potentially applicable demand management measures for the South Australian market. South Australia's sole electricity distributor, ETSA Utilities, was required to work closely with ESCOSA on the demand management program, and was subject to specific reporting requirements for each initiative.

The main elements of the initiative were:

- ESCOSA provided an allowance of $20 million for a range of pilot demand management initiatives in the AER's 2005–10 Distribution Network Price Determination for (ESCOSA, 2005, p. 53)
- Allowances for demand management are treated as operating expenditure, and are not imputed into demand forecasts, capex or the regulatory asset base. The classification of these initiatives as opex is a decision based on their 'pilot nature' (ESCOSA, 2005, p. 60).

Queensland Energy Conservation and Demand Management Program

In 2009, the Queensland Government committed $44.7 million in budget funds to the Queensland Energy Conservation and Demand Management (ECDM) Program. This program was implemented in collaboration with the two Queensland distribution network businesses, Energex and Ergon Energy and aimed to reduce peak demand by 40 MW, and deliver an

[47] Assuming the same 10 year average life for demand reductions implied by the cost of energy savings.

expected saving of $120 million in transmission, distribution and generation infrastructure (Queensland Department of Employment, Economic Development and Innovation 2011).

Main elements of the scheme were:

- It aimed to help avoid the equivalent of 1000 MW, saving more than $3.5 billion in avoided network and generation costs.
- Part of these savings came from DM targets adopted by distribution network businesses: 144 MW (Energex) and 103 MW (Ergon).
- Initial funds ($47 million) were provided by the Qld Government. Subsequent program cost recovery was sought from and approved by the Australian Energy Regulator (AER) (~$220million).
- If performance targets were not met, the AER could disallow cost recovery. (Queensland Department of Employment, Economic Development and Innovation, 2011)

In both 2010-11 and 2011–12, Energex's DM programs met its targets in its key commercial/industrial initiatives (26.1 and 42.6 MVA compared to targets of 26 and 42 MVA respectively) and exceeding them by almost double in its residential DM initiatives (15.4 and 23.4 MVA compared to targets of 8 and 12.5 MVA respectively) (Energex, 2012).

In 2011–12, Ergon DM activities delivered 36MW of demand reductions, exceeding the 25MW target set for the year. With 17MW of peak demand reductions the previous year, Ergon was well positioned to achieve its target of 103MW saving by 2015 (Ergon Energy, 2012).

This program and its legacy are largely responsible for Queensland distribution network businesses currently being widely regarded as the leaders in network DM in Australia.

***

Most of these efforts generally ended with reaction against the least cost approach. However on each occasion this reaction tended to be more muted than the one which preceded it. For example, in the case of the first efforts of the EANSW, the Authority was disbanded and its programs shut down. With the Victorian DM Action Plan, in 1994 the program was shut down and most of the staff reabsorbed into the utilities. The NSW SEDA was closed and absorbed in the Department of Energy Utilities and Sustainability, but some of its programs continued in other forms (SEDA 2005). However, in the case of the Qld ECDM, the program was simply scaled back and it continues to this day.

This increasing acceptance, or perhaps more accurately lessening resistance, to DM and least cost principles in Australia should provide cause for hope that the prospects for a balanced approach to the electricity sector in Australia are improving. Indeed, the recent dramatic rise in electricity prices has meant that the imperative to reduce costs has become urgent.

There are other reasons for believing that the era of least cost and efficient DM may soon arrive. These reasons include:

1. As the cost falls for variable output renewables, like wind and solar, and their share of generation output correspondingly rises, the need for resources to balance this variable generation output also rises. While traditionalists often recommend gas fired peaking generation or pumped hydro for this role, flexible DE such as peak load management and energy storage and even energy efficiency will in most cases be more cost effective.

2. As the level of investment in traditional centralised electricity supply (and in particular coal fired generation) declines and investment in DE options increases, the balance economic and political influences on policy will shift towards DE.

3. The climate change imperative. As the need for least cost carbon abatement solutions increases, the potential for energy efficiency, decentralised energy and demand management to provide low-cost and often negative cost solutions will be harder to resist.

8.2 Applying least cost competition in Australia's electricity sector

The electric power grid has been called 'the largest machine in the world' (Aggarwal, 2014). This description highlights that while the electricity system has many parts, it also constitutes an integrated whole.

Segments of the electricity system include:

- generation
- transmission and distribution networks

- retailing, metering and billing
- system control and ancillary services (relating to frequency and voltage control, etc.)
- electricity use by consumers.

However, despite their shared fundamental components, electricity systems are also diverse in their governance and market structures. They range from government-owned, vertically-integrated, centrally-planned, regulated monopoly systems to privately-owned, disaggregated, competitive market structures, with numerous variations in between. There are energy-only generation markets, as in Australia's NEM, and hybrid capacity/energy markets such as Western Australia's Southwest Interconnected System (SWIS). There are various ways of managing and procuring ancillary services ranging from administrative to competitive processes. Given this diversity of market and industry structures, there is no 'one size fits all' prescription for delivering least cost outcomes. This is also true for applying the principles of least cost competition.

To deliver least cost outcomes from vast and complex power grids, it is necessary to apply least cost principles *both* holistically *and* to the key system segments. Sections 8.3 to 8.6 considers these two dimensions.

Sections 8.3 considers the NEM as a whole system, and Sections 8.4 to 8.6 discuss how the principles of least cost competition may be applied within each segment of the NEM. Each section includes **recommendations** drawing on this analysis. Similar approaches to proposing policy recommendations to support DM has been adopted by Cowart et al (2001) and Cowart et al (2003). The recommendations here are numbered and labelled with a letter referring to which segment of the market they refer to as follows:

S: Whole electricity system; **G:** Wholesale generation market; **N:** Networks; **R:** Retail.

8.3 Least cost competition in the electricity system as whole

In the NEM, there are three overlapping energy markets. These are:

- the generation pool managed by the Australian Energy Market Operator (AEMO), into which all large-scale power stations competitively bid their electricity output every half hour, and from which all electricity retailers derive energy
- the wholesale contract market, which consists of financial hedges and other instruments traded between generators and retailers (and various intermediaries)
- the retail market between retailers and consumers.

Principle 1: Clear and appropriate purpose:

The first principle of least cost competition is setting a clear and appropriate purpose or objectives.

As noted in Section 7.3.1, the Australian National Electricity Market has an explicit purpose, as outlined in the National Electricity Objective (NEO). The NEO sets out a range of criteria that needs to be considered, including price, quality, safety, reliability and security. However, there is debate as to how clear and appropriate the current NEO is.

Just as the stability of a scientific paradigm over time is part of its strength and usefulness, so too a stable NEO is advantageous. Changes to the NEO should not be undertaken hastily or frequently and should be implemented only where there is a valid case that the NEO does currently not serve the needs of consumers and the community. On the other hand, to remain relevant, the NEO should be amenable to the changing needs and preferences of consumers and the community that the market is intended to serve.

On this basis, given that the NEM has failed to meet community and consumer expectations, it is timely to reconsider the NEO. The following are three steps that could be taken to amend the NEO to ensure that it promotes least cost competition.

Firstly, the NEO could be amended to focus on cost or bills, rather than price. To put it another way, the NEO could focus on providing the lowest possible electricity bills, rather than the lowest possible per unit electricity price. This would clearly encourage least cost energy services, whereas at present, the least cost objective is subordinate to other criteria, including minimising price.

As consumers derive value and utility from the services that energy provides, rather the kilowatt-hours or joules delivered, a focus on *least cost energy services* would better meet customers' needs. Electricity bills are a product of price and the volume of electricity consumed. The current focus on price conflicts with minimising bills because helping consumers to reduce consumption will reduce their bills but may lead to higher prices. For example, encouraging consumers to install rooftop solar panels, insulation or efficient lighting may reduce electricity purchases, consumption and energy bills, but may also mean that the fixed costs of electricity supply have to be recovered from a smaller volume of sales. Such an outcome is likely to lead to *lower* average electricity bills but *higher* per unit electricity prices, at least in the short term.

Secondly, to deliver least cost electricity, consumers should be involved in deciding what the appropriate objectives are for the NEM. The question of the appropriateness of the NEO is strongly linked to the issue of public participation and accountability. Given that the purpose of the NEO and the NEM is to serve the long-term interests of consumers, and consumers themselves are generally the best judges of their own interests, then it follows that consumers should have a say in what the objectives are.

Thirdly, there is a need to clarify how the NEO relates to other objectives relevant to the NEM. It is clear that the NEO does not encapsulate all of the policy objectives that the electricity system is intended serve and currently does serve. For example, the Renewable Energy Target sets an objective of growing the share of renewable energy. Similarly, the NSW Energy Savings Scheme (ESS) and the Victorian Energy Efficiency Target (VEET) are intended to serve environmental and affordability goals within the electricity sector. There are also social equity and welfare goals associated with disconnection policy and rebate programs. The formal inclusion of environmental, affordability and social equity criteria in the NEO would allow these considerations to be balanced more explicitly against the existing NEO criteria.

There is also a strong argument for including 'a fair return on investment' in the NEO. Given that return on investment is already a powerful objective in practice, it may be valuable to explicitly recognise it as one of the objectives to be balanced in the NEM. Alternatively, this goal could be implicitly included within a more generic criterion of 'fairness'.

However, there has been major resistance to changing the NEO. Within the NEM institutions and among energy policy makers, the dominant view has been that it is best to keep the NEO 'clean' and focused on economic and technical issues, unencumbered by more contentious criteria such as environment, affordability and social equity.

Changing the NEO would also be logistically difficult. The NEO is written into the National Electricity Law. To change this law would require agreement of all five states in the NEM and the Australian Capital Territory. It is unlikely that the governments of all these jurisdictions would see reform of the NEO as sufficiently urgent to warrant the effort required. So from a pragmatic point of view, it may be expedient to find other ways to establish clearer and more appropriate objectives for the NEM. Two options to achieve this are discussed below.

The first may be called the ‘interpretive option’. This option involves taking advantage of the ambiguity of the NEO to interpret it as implying a desirable objective, such as a least cost energy services objective. As the main clause in the NEO is ‘the long term interests of consumers’, this is a plausible strategy. Amending the National Electricity Rules would be one way of implementing this option. The rule change proposed by the Council of Australian Governments (COAG) Ministerial Energy Council to establish the Demand Management Incentive Scheme was a successful example of this approach (AEMC 2015).

The second may be called the ‘legislative option’. This involves enshrining in legislation any desirable objectives that are perceived to be excluded by the NEO. The existing Renewable Energy Target, the NSW Energy Savings Scheme and the Victorian Energy Efficiency Target are successful precedents for adopting such an approach.

Finally, it is important to recognise that the appropriateness of objectives varies depending on the context of different sectors of the system. What may be appropriate for the generation sector may not suit the network sector, and so on. This theme is developed further in sections 8.4 to 8.6.

Recommendation S1: *As consumers are intended to be the primary beneficiaries of the NEM, changes to the objectives of the NEM should involve a fair and open process of public participation.*

Recommendation S2: *Subject to recommendation #S1, the NEM should adopt least cost to consumers, fairness and environmental sustainability as explicit objectives, in addition to the existing objectives of safety, quality, reliability and security.*

Principle 2: Public participation and accountability

The second principle of least cost competition is effective public participation and accountability. Section 7.3.4 highlighted the importance of effective public participation and accountability in least cost planning. This principle is not just applicable to least cost competition; it is crucial to ensuring the legitimacy and appropriateness of the design and governance of any modern electricity system. As noted above, it is also crucial to setting and amending objectives for an electricity system.

Public participation and accountability have been part of the NEM since its inception. The key issue here is how effective this public participation and accountability have been, and how changes can be introduced to facilitate least cost outcomes.

The extent of public participation has fluctuated throughout the history of the electricity system in Australia. The electricity supply system in Australia first emerged from local community engagement in the form of local governments that provided street lighting for social amenity. As noted in Section 8.1.1, once the supply system was centralised through the establishment of state-based electricity commissions in the 1950s, decision-making also tended to become more centralised and technocratic, and public participation was relatively limited. In some cases, this led to political conflict and crises of legitimacy, and even commissions of inquiry such as the McDonell Inquiry in NSW in 1985–86, as discussed by Rosenthal and Russ (1988), Booth (2003) and Beder (2003).

In response to these concerns, in the 1980s there was a renewed push for greater public participation and accountability, including greater consultation and transparency in power station development, and more formal and independent revenue and price setting for electricity networks through state-based regulators such as the IPART of NSW, the Essential Services Commission of Victoria and the Queensland Competition Authority.

This period was accompanied with electricity prices falling in real terms, (both prior to and following the liberalisation of electricity markets). It is therefore not surprising that when the NEM was first proposed, at a time when power generation was emerging from this period, there was significant public consultation.

However, given the highly technical nature of electricity market, public participation in the detailed design of the NEM was very limited. Its development and design was driven by the electricity supply industry itself. It is therefore not surprising that supply-side perspectives dominate the design of the market. However, public participation in the design of the market should not be a matter of “set and forget”. There should be meaningful opportunities for public participation and engagement in the ongoing evolution of the design of the market.

As electricity prices trended down in the 1990s and early 2000s, the electricity market became less contentious. However, when electricity prices rose sharply again after 2007 (after network price regulation was transferred to the national regulator, the AER), the limited scope for public participation again arose as a significant issue.

Through a series of reviews in 2012–13, the need for better consumer consultation and public participation was highlighted. This led to the establishment of Energy Consumers Australia (ECA), a government agency dedicated to advocating for residential and smaller business consumers. One of the key actions instituted by the new ECA was to regularly assess consumer attitudes to the electricity market through an Energy Consumer Sentiment Survey. An illustration of the level of consumer dissatisfaction is shown in Figure 8-6.

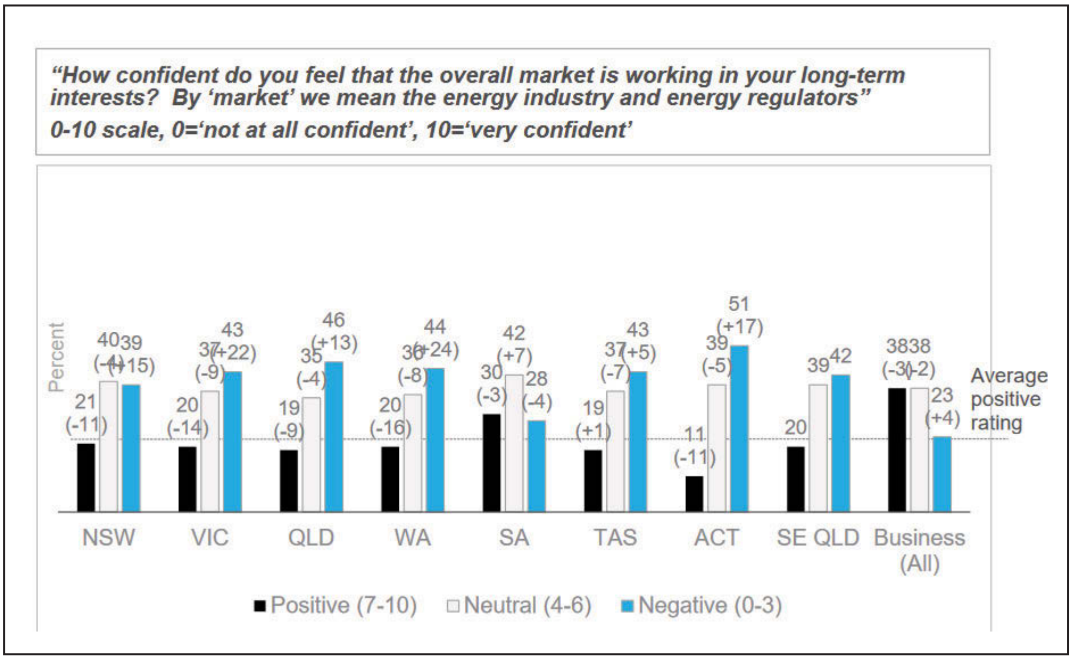

Figure 8-6 Level of consumers satisfaction with the Australian energy market (Sept 2017) (Energy Consumers Australia, 2017)

As shown, the level of dissatisfaction is high, particularly among residential consumers.

Accountability is the other side of the public participation coin. The NEM's failure to meet public expectations may be less attributable to inappropriate objectives, or to a lack of effective public participation, and more due to a lack of effective public accountability.

There has been some progress towards improved accountability in recent years. This includes the development of the *State of the Energy Market* report, published annually since 2008 (Australian Energy Regulator, 2017) and recently the publication of the annual *Health of the National Electricity Market* first published in December 2017 (Energy Security Board, 2017). Both of these documents include useful and important information regarding accountability against the national electricity objective, and more broadly regarding the interests of consumers. However, neither of these two reports has a clear line of reference back to the express desires and priorities of consumers.

Key reforms are still required. Firstly, more effective participation of a broader, more representative range of stakeholders is needed. Secondly, there needs to be stronger accountability against the NEO and objectives of the electricity system. These two reforms are inextricably linked. Public participation is likely to be effective only if it is informed by accountability of the electricity system's institutions in responding to public concerns, and accountability is only meaningful if it addresses identified issues of public concern. Current performance reporting is inconsistent and lacks transparency. For example, the *Health of the National Electricity Market* records a number of indicators as being either 'being monitored', or 'critical'. However, the meanings of 'being monitored' and 'critical' are not defined, and nor are the methods by which they are applied to specific performance categories.

One of the major challenges in encouraging public participation is supporting consumers and other stakeholders to participate meaningfully. On the one hand, utilities have access to significant resources to engage in consultation and policy debates, while on the other, electricity consumers are generally diffuse and uncoordinated, with little time and resources to engage in complex energy policy debates.

Recommendation S3: *The current public participation mechanisms should be strengthened and their scope broadened to include, for example, questions of the appropriate objectives for the National Electricity Market.*

Recommendation S4: *The current public accountability mechanisms for the National Electricity Market should be improved to include clear and consistent reporting on performance against all objective criteria including least cost outcomes, safety, quality, reliability and security, fairness and environmental sustainability.*

Recommendation S5: *The accountability for the NEM should include annual consideration and reporting of current and proposed reforms to better meet priority objectives identified via public participation.*

Principle 3: Cost-reflective pricing

More cost-reflective pricing is crucial to the efficient operation of the NEM. This is particularly so in the context of the rapidly rising penetration of variable output solar and wind generation. The principle of cost-reflective pricing is relevant to the wholesale market in generation, to the transmission and distribution network segments, and to electricity retail pricing. The application of cost-reflective pricing is discussed in each of the segment sections below.

Recommendation S6: *The accountability of the NEM should include annual consideration and reporting of current progress towards more cost-reflective pricing and proposed reform to expedite this progress.*

Principle 4: Competition among all viable options

Some of the strongest advocates for greater efficiency through competition in generation and retail supply have been restrained in their support for mechanisms that would encourage efficiency in relation to decentralised energy resources. For example, the same 1991 Industry Commission report that supported major competitive reform in the generation sector, also made the following statement in relation to energy efficiency:

> The range of energy conservation initiatives pursued by governments includes the provision of energy efficiency information to consumers, labelling appliances and energy rating buildings, prohibiting the sale of relatively low efficiency appliances and prescribing particular standards

> (e.g. insulation). These latter measures severely curtail consumer choice. It is not clear whether such actions are warranted. It needs to be established that these programs can provide net benefits to society, taking into account both direct and indirect costs (Industry Commission, 1991, p. 14).

This perspective raises the question of whether mechanisms to support energy efficiency and other decentralised energy resources would enjoy greater acceptance among policy makers if they were established as a competitive market mechanism rather than as administered programs and standards. Least cost competition involves such an approach. Section 8.6.4 discusses how cost effective energy efficiency in particular can be included in the market.

A further problem in relation to considering all viable options, is the reference in the NEO to 'electricity services', as opposed to 'electricity' or 'electricity supply'. From one perspective, the Australian Energy Market Commission has offered an enlightened interpretation of this term:

> The energy objectives reference services, not assets. In other words, the scope of the objectives includes how energy is used, rather than what it is or how it is delivered. Energy consumers care about what they use their energy for, from heating water in residential homes to helping to run a small business to powering large-scale manufacturing processes. This is a key consideration in the way in which we frame our decisions and advice, because it means we take into account the interaction between demand and supply when we think about the outcomes for consumers. (AEMC, 2016a, p. 6)

This very positive interpretation appears to embrace the concept of "energy services" which is fundamental to least cost principles. However, this interpretation also appears to be in direct contradiction with the National Electricity Law, which defines electricity services as follows:

> ***electricity services*** means services that are necessary or incidental to the supply of electricity to consumers of electricity, including—
>
> (a) the generation of electricity;
> (b) electricity network services;
> (c) the sale of electricity; (South Australian Government 2016, p. 26)

The processes for considering all potentially viable options are discussed in relation to each electricity system segment below (Sections 8.4 to 8.6).

Recommendation S7: *The accountability of the NEM should include annual reporting of performance in fairly considering all potentially viable supply-side and demand-side options and should propose reforms to improve this performance where necessary.*

Principle 5: Competition based on all relevant costs

In order to achieve a least cost outcome, it is essential to define which costs are included. An effective process of public participation is required to decide which costs are relevant to be included. This is particularly important for governments in deciding whether and how to include external environmental costs such as in relation to carbon emission.

If all relevant external costs are effectively included in the competitive segments of the electricity system, then the non-competitive segments such as network businesses can focus on the direct costs to their business in pursuing least cost outcomes.

The processes for considering all relevant costs are discussed in the relation to each market sector below.

Recommendation S8: *The accountability of the NEM should include annual reporting of current performance in fairly considering all relevant costs and propose reform to improve this performance where necessary.*

8.4 Least cost competition in electricity generation

In the liberalised Australian NEM, generation and retail sectors are ostensibly competitive markets. However, even in these nominally competitive markets, there are major barriers to effective least cost competition, particularly in relation to DM and decentralised energy.

For the purposes of least cost competition, there are five key components of the generation segment of the electricity system:

1. the wholesale spot market for generation, where generators bid into a competitive half-hourly auction to be "dispatched" (that is, they are requested to generate)

2. the wholesale contract market, between generators and retailers

3. the generation ancillary services market, where generators, and recently some demand-side resources, bid in an auction to provide specific support services to maintain the quality, reliability and security of supply

4. protection of system wide reliability and establishing a strategic generation reserve

5. the Renewable Energy Target

This section considers how to apply least cost competition to each of these components.

8.4.1 Wholesale spot market

All generators above 30MW capacity are required to participate in a wholesale spot market, or 'pool'. The spot market operates as an auction in which each generator offers quantities of generation output at a specified price for each five-minute period. All of these 'bids' are then ordered, or 'stacked', from the lowest offered price to the highest. Generators are then called on to generate or 'dispatched' for each five-minute period, starting with the lowest-offer price generator, and then the next lowest, and so on until the dispatched generation is equal to forecast demand, as illustrated in Figure 8-7. The highest-priced offer needed to meet demand sets the dispatch price. These dispatch prices are then averaged over each half-hour period to set the settlement price (AER, 2017a, p. 24).

Given the competitive nature of this process, it is quite appropriate that the objectives for the wholesale electricity spot market should focus on lowest price and supply adequacy. In the context of the competitive pool, other potential objectives for the electricity system as a whole, such as minimising bills or costs, or supporting social equity are arguably best served by a focus on tapping the lowest-priced resources. However, the appropriate objectives *for the generation spot market should* not be confused with the appropriate objectives for the electricity system as a whole.

However, there is one major caveat to this approach: the current structure of the wholesale spot market ***does not support*** the dispatch of the lowest priced resources because it excludes demand management. In this respect, it diverges from the least cost competition principle of including ***all viable options***.

Figure 8-8 summarises how least cost competition could be applied to the wholesale spot market. The reforms indicated in the figure are discussed below.

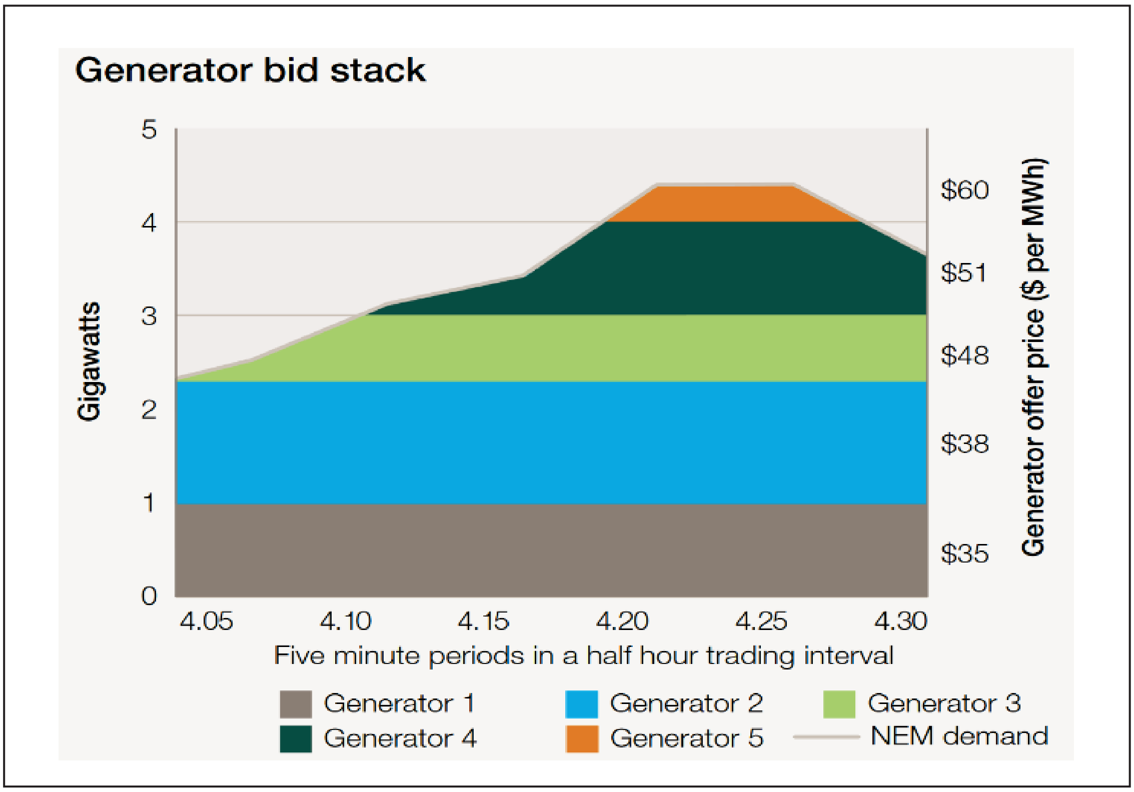

Figure 8-7 Stacking generator bids in the wholesale spot market

(AER 2017a, Fig 1.3)

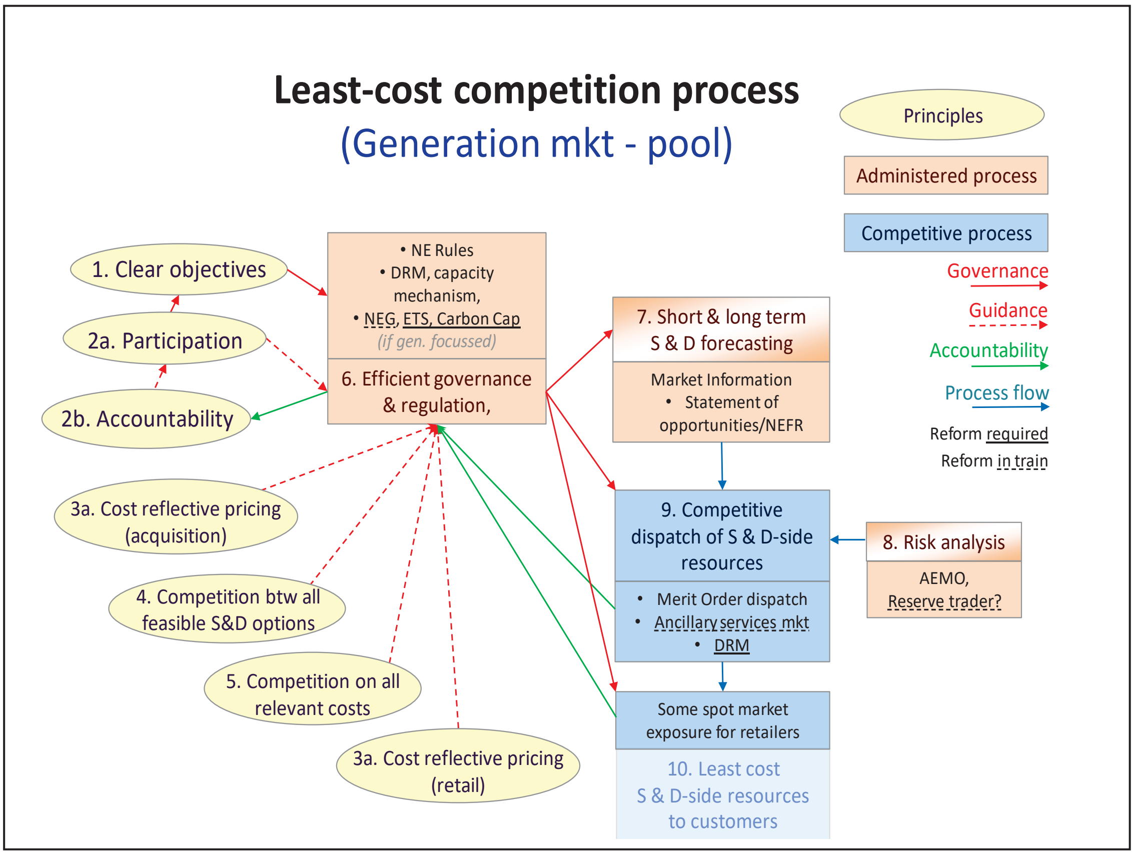

Figure 8-8 Least cost competition in the generation (wholesale spot) market segment

In the wholesale spot market, there is currently no provision for demand management to compete directly with generation. That is, the spot market is effectively a generation-only market. Within this market, generation prices can on occasion rise to the market price cap (MPC), which is currently $14,200/MWh (AEMC, 2018a)[48].

At times of such high wholesale pool prices, the cost of demand management, in the form of short term demand response (DR), is likely to be often much lower than the marginal price of the marginal generator. If DR was permitted to participate, this could have very significant benefits for consumers in lowering pool prices and consequently average electricity prices and bills. It would also reduce the need for additional generation capacity.

In 2009, the US Federal Electricity Regulatory Commission (FERC) estimated savings available through demand response of up to 20% or 188GW of peak electricity demand in the United States by 2019 (FERC, 2009, p. xii).

As noted in Section 6.5, the original National Grid Protocol in 1992 stated that, ‘Demand management and renewable energy options are intended to have equal opportunity alongside conventional supply side options to satisfy future requirements’ (National Grid Management Council, 1992, p. iii).

However, when the NEM started in 1998, there was little explicit attention given to demand management, and a demand management mechanism was not included in the wholesale spot market.

In 2002, the Council of Australian Governments (COAG) commissioned a major review of the energy market in Australia. This review, which became known as the Parer Review (after its chair, former Howard Government federal energy minister, Warwick Parer) recommended:

> The NEM mechanism should be amended to include a demand reduction bidding option that would enable load reduction to be bid into the NEM for dispatch and payment in competition with generation offered into the market to meet demand. (Council of Australian Governments Independent Energy Review Panel, 2002, p. 183)

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[48] For the 2017-2018 financial year the MPC is $14,200/MWh and the Cumulative Price Threshold is $212,800 for the same period. https://www.aemc.gov.au/news-centre/media-releases/aemc-publishes-schedule-reliability-settings-2018-19

However, this recommendation was not adopted and demand response was not included in the wholesale electricity market.

In November 2012, the Australian Energy Market Commission, as part of its Power of Choice review, also recommended allowing DR to participate in the spot market, stating,

> A demand response mechanism [DRM] is introduced that pays demand resources via the wholesale electricity market (rewards changes in demand). Under this mechanism demand resources would be treated in a manner analogous to generation and be paid the wholesale electricity spot price for reducing demand. We recommend that AEMO develops the details for a rule change proposal and required procedures, including the baseline consumption methodology (AEMC 2012a, Rec 11. p. ii).

This recommendation was supported by the federal government, leading to a proposed rule change in March 2015 by the COAG Energy Council (Ryan, 2015). After more than four years of public debate and consideration by government, in November 2016, the AEMC rejected the rule change it had itself recommended, ostensibly for the following reasons:

> 1. Under the DRM, spot prices will not reflect competition from demand response …
> 2. The DRM requires costly changes to the wholesale market and retailer systems …
> 3. The DRM will not necessarily alleviate network constraints and defer network expenditure …
> 4. The DRM can have unintended consequences and create distortions in the spot market and other related markets (AEMC 2016, pp. 8-9).

It is beyond the scope of this thesis to refute in detail these arguments, but this decision was widely criticised as illogical and imprudent. For example, the Public Interest Advocacy Centre stated:

> Hence, the introduction of a Demand Response Mechanism (DRM) was recommended by the AEMC in the 2012 Power of Choice review. Subsequently AEMO developed a rule change proposal to this end. In response to pressure from incumbent gentailers[49] - who, as noted by the AEMC, face conflicting incentives [with] respect to DR and generation (AEMC 2017)[50] –

[49] *Footnote in original quote:* 'Retailers have repeatedly claimed that DRM implementation costs exceed $100 million. These claims remain entirely unsubstantiated, have been questioned by independent experts and have not been subject to any meaningful due diligence, yet they have been treated seriously by the AEMC and others.' (PIAC)
[50] *Footnote in original quote:* 'AEMC, Reliability Frameworks Review Issues Paper, 22 August 2017, p. 54' (PIAC)

> AEMO [51] did not lodge a rule change proposal for the DRM with the AEMC, instead deferring to SCER[52].
>
> SCER opted to delay the reform by a year with (another) cost-benefit analysis. In 2014 when Ministers met again to consider a DRM, gentailers argued the reform would no longer be of benefit, due to declining demand and oversupply of generation capacity; a position proven short sighted by recent history.
>
> In 2015, this resulted in a modified rule change proposal by COAGEC, for a DRM that was, by design, ineffective in that it gave retailers the right to disallow consumers from participating.
>
> While AEMC could clearly not approve such a design, PIAC is disappointed to see the AEMC make this decision on the basis of analysis that was deeply flawed on a number of counts.
>
> For example, in considering that rule change, the AEMC came to the conclusion that *"retailers themselves offer, or are willing to offer, a range of products and services intended to capture a customer's demand response",* citing estimates of more than 2,000MW of DR already in the market and painting a picture of an emerging demand side market requiring no intervention along with abundant reliable generators that provide capacity when needed.
>
> In 2017, the reality paints a different picture. The involuntary load curtailment that blacked out some South Australian households in summer 16/17, made necessary by generator failures on the day, could have been avoided if just 100MW (3% of the South Australian load) was voluntarily turned off. By comparison, more than 10% of Western Australia's wholesale market capacity comes from demand response, as it is allowed to participate in the wholesale market. (PIAC, 2017, pp. 5-6)

A third review of the NEM in 2016, led by the Chief Scientist, Alan Finkel, again recommended that the DR be included in the wholesale spot market.

> The COAG Energy Council should direct the Australian Energy Market Commission to undertake a review to recommend a mechanism that facilitates demand response in the wholesale energy market. This review should be completed by mid-2018 and include a draft rule change proposal for consideration by the COAG Energy Council (Finkel et al., 2017, p. 148).

[51] *Footnote in original quote:* AEMO is a half owned by the state, territory and federal governments and half owned by the electricity market participants, including "the incumbent gentailers".
[52] *Footnote in original quote:* The SCER was the (ministerial) Standing Council on Energy and Resources. Its predecessors prior to June 2011, were the Ministerial Council on Energy and the Ministerial Council on Mineral and Petroleum Resources. Its name was changed to the COAG Energy Council (COAGEC) in December 2013.

At the time of writing this thesis, it remains to be seen whether, on this occasion, the recommendation will be implemented.

While every electricity market is different, there is little doubt that it is technically possible to introduce demand response into the NEM wholesale spot market. For example Singapore, which has a similar market structure to Australia's, introduced DR into its electricity wholesale spot market in 2016. Ironically, an Australian electricity retailer, Diamond Energy, was the first electricity retailer to be approved by the Singapore Energy Management Company (EMC – the equivalent of Australia's AEMO) to offer DR into the Singapore National Electricity Market, in October 2017 (Soh 2017).

It appears that the barriers to the introduction of DR are not technical, but more related to how DR may impact the commercial position of influential players within the market. As Memery contends,

> The DRM is a reform that's good for consumers, but the energy retail and generation sector feels threatened by it – it's competition, after all – and wants it stopped.
>
> Last December, the gentailers[53] prevailed: through a well-resourced, behind-the-scenes lobbying campaign, they persuaded ministers to delay the reform by a further year with (another) cost-benefit analysis (Memery, 2014).

The introduction of DR into wholesale electricity market is not just contentious in Australia. As Ata et al. comment:

> The direct participation of DR providers in the wholesale markets, and how to compensate such resources has been a controversial issue in the policy making circles.
>
> In March 2011, the Federal Energy Regulatory Commission (FERC) issued Order 745, and ruled that organized wholesale market operators must pay the market price for energy to demand response providers when such resources have the capability to balance supply and demand as an alternative to a generation resource and when their dispatch is cost-effective. (FERC, 2011)

In May 2014, the U.S. Court of Appeals for the District of Columbia Circuit 'vacated' Order 745, agreeing with a group of electricity generators that the agency had overstepped its legal authority and regulating the retail electricity markets is the exclusive legal right of each state,

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[53] "Gentailers" are large integrated generation and retail companies.

without federal intervention. Nonetheless, in January 2016, the Supreme Court majority disagreed with the Court of Appeals and ruled that demand response is primarily a wholesale market function, and FERC Order 745 addresses only wholesale market transactions (Bade, 2016; Ata 2017).

Opponents of reforms which would introduce DR to the spot market maintain that there is currently no barrier to DR in the spot market, and there is an element of truth in this. While it is not possible for DR to bid directly into the generation spot market as generators can, both customers and retailers can participate by responding to high prices in the spot market by reducing demand. However, this form of DR is only useful for customers if they are directly exposed to high prices in the spot market. Very few customers have the capacity or the appetite to take on this risk.

While electricity retailers generally do have exposure to the spot market, the larger retailers also own or have interests in generators that stand to gain from high pool prices, so they may be unenthusiastic about making the most of DR opportunities. In principle, customers of such gentailers will have an incentive to switch to retailers who are more proactive on DR, but in practice, customers have complex motives in their choice of electricity retailer and may not be inclined or able to switch easily. The DRM solution that has been put forward is to allow customers to stay with their existing retailer, but to be able to bid their demand reduction directly into the spot market through another party, such as a DR ‘aggregator’.

There are two conceptual problems that need to be overcome to allow DR to be bid into the spot market. The first is the issue of ‘baselines’. It is harder to meter or measure DR directly than it is measure generation, and generally DR must be estimated. Since DR is by definition a reduction in demand compared to what otherwise would have occurred, it is necessary to subtract measured demand from the expected baseline demand (that is, expected demand in the absence of DR) in order to estimate the volume of DR provided. Therefore, this baseline of expected or ‘business-as-usual’ demand needs to be established. While setting baselines is not an exact science, there is a very large, well-established body of precedents, methods and analysis which generally provides a sound and rigorous method for estimating baselines. The most comprehensive such resource is probably the voluminous International Performance Measurement and Verification Protocol (IPMVP), published and maintained by the Efficiency Valuation Organisation (2018).

The second problem is how to account for the impact of the estimated DR in the operation of the spot market. At first glance this might seem straightforward: simply pay the customer providing the DR the spot price in the market multiplied by the estimated volume of DR provided, just like a generator. However, this creates an arithmetical problem, as now the total volume of electricity bought from generators and DR providers exceeds the total volume of electricity sold to retailers and consumers.

To illustrate, imagine that the total demand for electricity during the peak hour of the year is 100 megawatt hours (MWh). Consequently, the total electricity being sold by generators into the spot market is 100 MWh and the total volume of electricity being bought by retailers and spot market-exposed customers is also 100MWh. This means that the total revenue collected from customers in the market is equal to the total paid out to generators and the market 'clears'.

Now imagine that DR is permitted to bid into the spot market and 5MWh of the 100 MWh of generation is replaced with 5MWh of DR (because it is offered at a lower cost than the most expensive 'marginal' generation). The total energy capacity bought by the spot market remains 100 MWh (95 MWh of generation and 5 MWh of DR), but now the total energy sold is just 95 MWh. In this case, the total revenue from the market is less than the total value of expenditure to be paid out to the resource providers (generators and DR providers). An accounting adjustment is therefore required to ensure that purchases and sales of electricity resources are brought into alignment.

An elegant solution to this problem of how to incorporate demand response into the Australian NEM wholesale pool was proposed in 2012 by DR aggregator, EnerNOC, as illustrated in Figure 8-9 (Troughton, 2012).

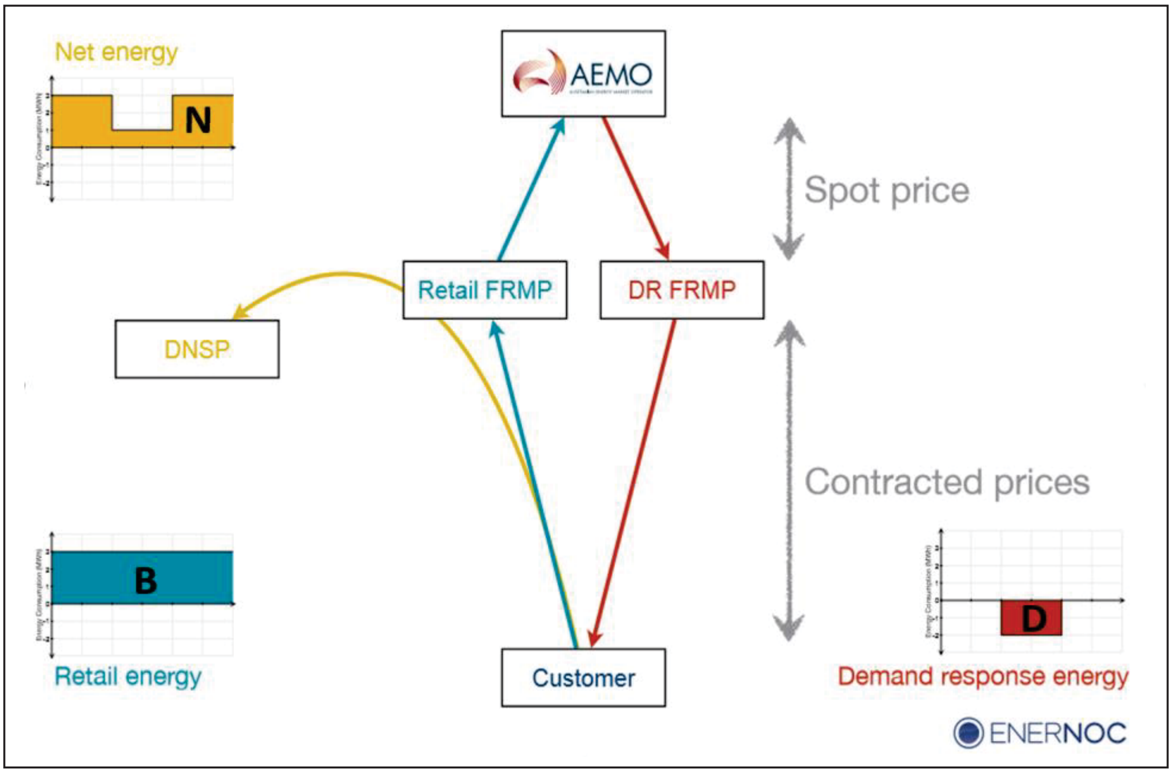

Figure 8-9 EnerNOC proposal for incorporating DR into the wholesale spot market (Troughton, 2012)
FRMP: financially responsible market participants;
DNSP: distribution network service providers, i.e. network businesses.

The EnerNOC approach is an adaptation of an existing arrangement whereby small-scale 'embedded' generators behind the retailer's customer meter can be metered and aggregated and bid into the wholesale market. EnerNOC's approach applies the same mechanism to demand response.

Just as the electricity output of small-scale generators need to be aggregated and metered "behind the meter" for a host retailer, so too there is a need to separately 'meter', or rather estimate, the demand response that is being provided behind the meter of the host retailer. The only difference is that in place of metering the output of the embedded generator, the volume of demand response 'D' is estimated by subtracting the actual metered customer load 'N' from the baseline of consumption for the host retailer 'B', which is the estimated consumption if the demand response was not dispatched.

The customer pays the retailer for the full baseline volume of electricity 'B' at to their normal contracted prices, and the retailer pays into the spot market for the same amount, 'B' at the spot price as usual. Then, the spot market pays the DR aggregator (DR FRMP) for the DR which has been dispatched at the spot price, and the DR aggregator pays the customer at the contracted price of DR. The retailer would pay the DNSP as usual for the volume of net energy actually delivered, 'N'.

This arrangement would only apply on occasions when the DR is dispatched. These occasions are likely to be rare and will occur at times of high demand, supply constraints and high spot prices.

There is of course no obstacle to the retailer acting as the DR aggregator in this model too, and bidding DR into the spot market. However, as the net result of the retailer acting as the D aggregator for its own customers would be essentially identical to simply contracting for DR with its own customers, it may prefer to adopt this latter, simpler approach.

Calculating baselines

The volume of DR calculated as delivered depends on the established baseline. If DR is permitted to bid into the spot market, and providers are paid for the volume of DR that is delivered, then both DR aggregators and customers providing the DR would, at least in principle, have an economic incentive to seek to maximise their baseline and therefore maximise their estimated volume of DR. Similarly, the higher the baseline, the greater the exposure of the host retailer to high spot prices. Hence, the host retailer will in principle have an incentive to seek to minimise the baseline. Simon Camroux, Manager of Wholesale Markets Regulation at AGL, one of the Australia's largest gentailers, used this issue to argue against the creation of the Demand Response Mechanism in 2013, stating,

> The operation of the proposed mechanism hinges on the volume of the users load reduction against its baseline energy consumption ... The customer, at the request of the [demand response aggregator], would reduce their load and subsequently be paid the difference between its baseline and actual consumption – with the [demand response aggregator] collecting some portion of these funds. This is the foundation stone of the demand response mechanism. A foundation stone that is substantially weakened by the fact that its existence creates a strong incentive to inflate the baseline energy consumption… (Camroux, 2013)

Clearly, the setting of the baseline cannot simply be left to the DR aggregator, the DR customer or the host retailer to determine. Some form of clearly defined, standardised method of setting the baseline is required. However, while in principle this is a potential problem, in practice it was resolved in designing the proposed Demand Response Mechanism for the NEM.

The system operator, AEMO proposed a simple, transparent and easily verifiable method for setting the baseline.

> For non-holiday weekdays [Baseline Consumption Methodology – BCM] Combination One employs the [Californian Independent System Operator's] 10 of 10 BCM, which typically sets the baseline energy for a trading interval based on the average of the metered energy for that trading interval for each of the prior ten most recent non-holiday weekdays that were not event days. (AEMO, 2013, p.17)

This approach is illustrated in Figure 8-10.

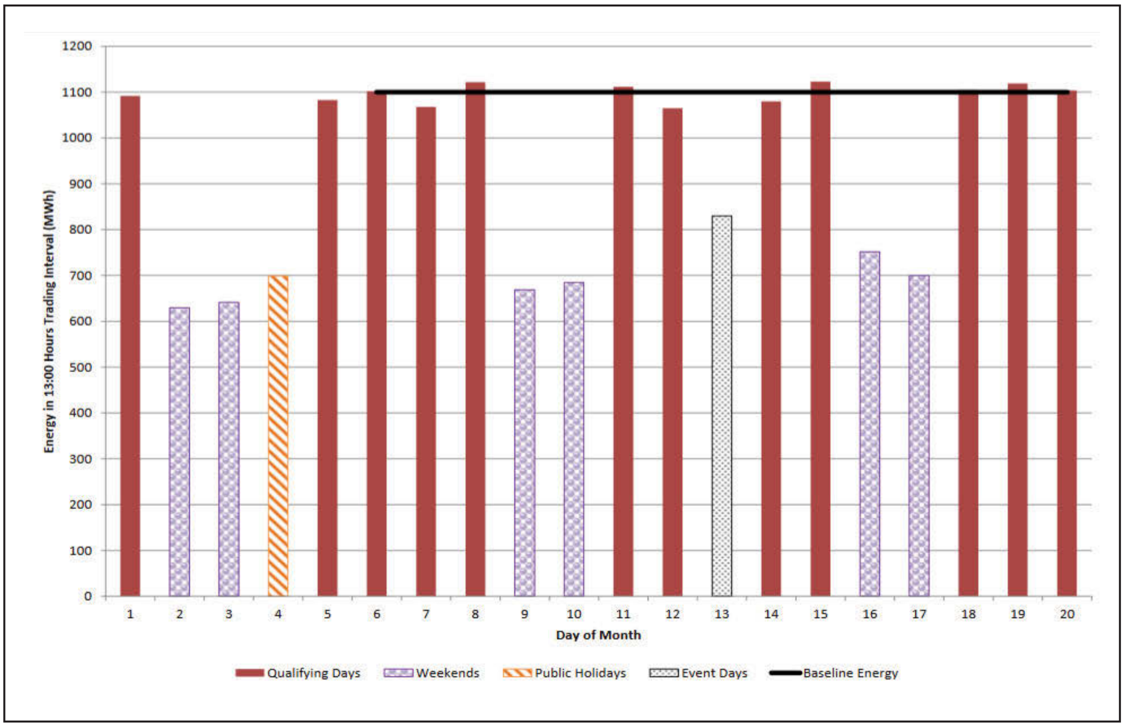

Figure 8-10 Setting consumption baseline for DR using "10 of 10" method
(AEMO, 2013, p.17)

Furthermore, AEMO would have responsibility for dispatching the DR. Consequently, AEMO and any other person with access to the 30-min interval meter data (such as the aggregator, the customer, or host retailer) can calculate the baseline in real time, and understand the impact of DR on the load of the customer.

8.4.2 The wholesale contract market

The wholesale contract market, which involves generators and retailers, is a relatively free market that consists of a wide range of financial instruments, such as 'caps', 'swaps' and various hedges and options that serve to help retailers and generators to manage risk associated with the relatively volatile spot market[54].

Figure 8-11 summarises how least cost competition may be applied to the wholesale market. The elements of this approach are described below.

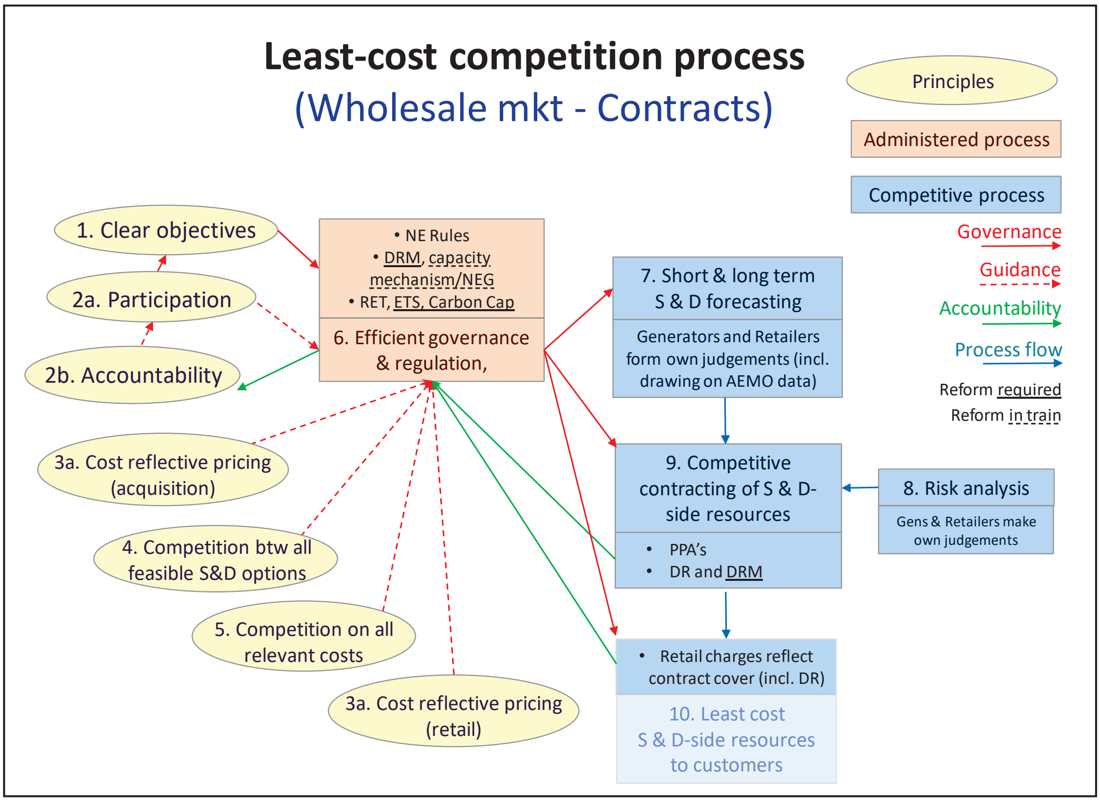

Figure 8-11 Least cost competition in the wholesale contract market

When the liberalised, competitive electricity markets were first created in Australia, there was a deliberate intention to separate generation from retail and network functions. For example, in Victoria, the vertically integrated State Electricity Commission of Victoria, which was responsible for generation, transmission, distribution and retail functions, was separated into each of these segments and sold off to separate buyers. The competitive market was seen as the best means of ensuring efficient low-cost outcomes for consumers.

However, despite the existence of a mature and flexible contract market, retailers and generators saw value in re-aggregating into combined generation and retail companies, or 'gentailers', and were permitted to do so. Consequently, as illustrated in Figure 8-12 and

[54] For a brief description of key financial instruments used in the NEM, see Marsden Jacob 2018, p. 70.

Figure 8-28, both the generation and retail markets are today dominated by the three large gentailers: AGL, Origin and Energy Australia.

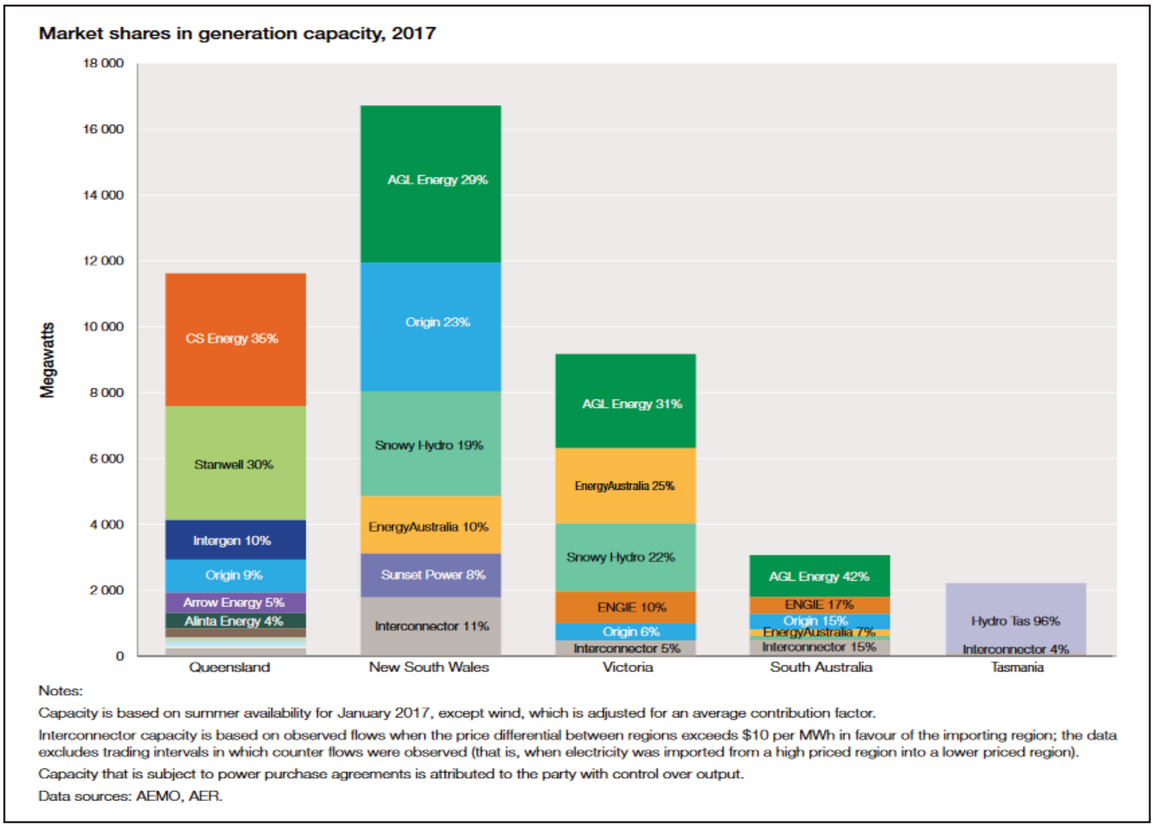

Figure 8-12 Concentration of generation market by capacity in the NEM
(AER 2017)

A commonly used measure of market concentration is the Herfindahl-Hirschman Index (HHI). As shown in Figure 8-13, the Australian generation electricity market has a Herfindahl-Hirschman Index of between 2000 and 2500. In the UK, OFGEM states:

> Figures for electricity were 1,353 and 1,247 respectively. The [UK Competition and Market Authority] typically regards markets with HHI below 1000 as unconcentrated, markets with HHI between 1000 and 2000 as concentrated, and markets with HHI above 2000 as highly concentrated (OFGEM, 2017, p.20).[55]

[55] "The Herfindahl–Hirschman Index (HHI) measures market concentration by summing the squares of the market share of each player. It provides insights into how competitive a market is. The closer a market is to being a monopoly, the higher will be the measure of concentration (see CMA market investigation guidelines, p.87)." (OFGEM, 2017)

The Australian electricity generation market would be considered highly concentrated according to this measure.

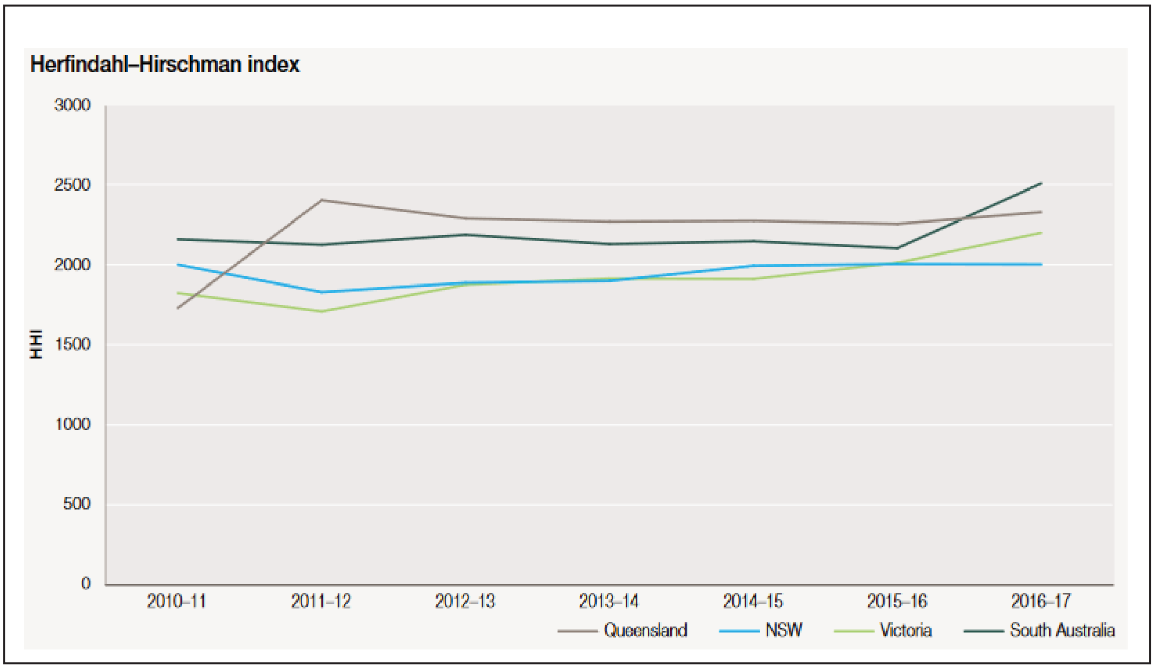

Figure 8-13 Level of generation market concentration in the NEM
(AER 2017, p. 48)

The contact market also includes DM in the form of DR contracts, but these are relatively rare and generally exist in the retail contract market between retailers and consumers. Just as the existing contract market has grown up around the existing generation-only spot market, if the spot market is opened up to DR, then it is likely that the wholesale contract market will become much more active in engaging with DR contracts.

The large gentailers have been accused of blocking or failing to embrace DR, on the grounds that higher generation prices are in their interest. However, this argument assumes that the gentailers have sufficient spare generation capacity to avoid exposure to high pool prices. (That is, their generator arm benefits more from high prices in the spot market and consequent impacts on the contract market than their retail arm suffers from such high prices). As existing coal fired power stations close and are replaced by variable output renewables, this argument is expected to weaken and there should be a stronger incentive for the large gentailers to tap DR as a low-cost resource for peak capacity .

Recommendation G9: *Commonwealth, state and territory governments should support a Demand Response Mechanism in the wholesale spot market. This will also encourage more Demand Response in the contract market.*

8.4.3 Generation ancillary services market

The primary role of generation market is to provide energy to consumers. However, the system operator, AEMO, also relies on generators to provide other ancillary technical functions that are crucial to the reliability, security and stability of the system. These ancillary services are:

- frequency control ancillary services (FCAS)
- system restart ancillary services (SRAS)
- network support and control ancillary services (NSCAS).

The recent annual costs of these ancillary services are as follows.

- frequency control ancillary services: between $23 million and $38 million pa (2010 to 2014) (AEMO, 2015, p. 6)
- system restart ancillary services: between $21 million (2015/16) and $22 million pa (2016/17) (AEMO, 2017, p. 6)
- network support and control ancillary services (NSCAS): $10 million and $44 million pa (2012/13 to 2016/17) (AEMO, 2017, p. 8)

In the NEM, there are eight sub-markets for procuring sufficient FCAS at any given time, including regulation and contingency services (AEMO, 2015, p. 8). Decentralised energy resources can in principle provide these services, but until July 2017, the National Electricity Rules only permitted generators to participate in the FCAS market. Demand response (DR) has long been used as an FCAS resource overseas. For example, DR has participated in the FCAS market in New Zealand for at least eight years (Strahan, et al, 2014, p.5).

The stark difference between New Zealand and Australia in the adoption of DR for FCAS is illustrated in Figure 8-14. 'Fast raise contingency' is one form of FCAS sub-market that is particularly suited to DR. As shown in Figure 8-14, in September 2016, DR represented 72 per cent of the fast raise contingency FCAS in the New Zealand Wholesale Electricity Market, while it only made up about 1 per cent of the equivalent category in the same month in the Australian NEM.

Further highlighting the enormous untapped potential of decentralised energy, and DR in particular, Strahan et al., note that New Zealand's National Grid operator, Transpower, "ultimately has a target of obtaining 10% of peak national demand (6500 MW) through DR" (Strahan, et al, 2014, p.5). To achieve a similar 10% of peak demand in the Australian context would be 3500 MW, roughly equivalent to the peak capacity of the Snowy Mountains hydro-electric scheme, and about twice the size of the proposed Snowy 2.0 upgrade.

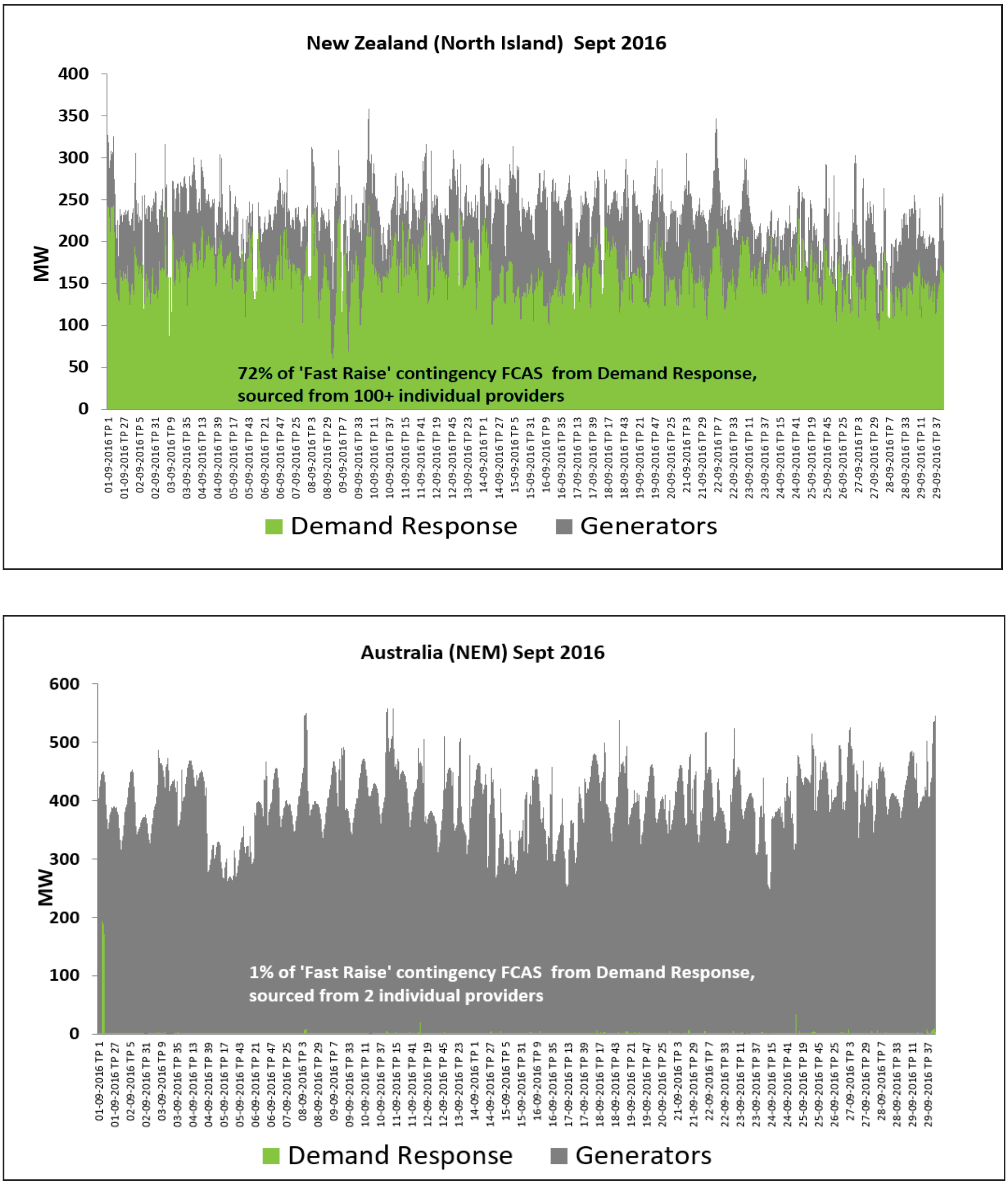

Figure 8-14 Comparison of DR vs. generation in FCAS markets; NZ and Australia
(Grover 2017, p.10)

However, this also illustrates the potential to grow rapidly the contribution of decentralised energy in Australia. Following a rule change to allow the unbundling of FCAS from other retailing services, DR aggregators were allowed to bid DR into the FCAS market in the NEM from July 2017. Figure 8-15 illustrates the rapid adoption of DR in FCAS (highlighted in blue) following this rule change. Although the FCAS market is only about 0.1% the size of the whole NEM in terms of annual turnover ($20 million vs. $20 billion), this reform is an encouraging harbinger of what decentralised energy can deliver when institutional barriers are removed.

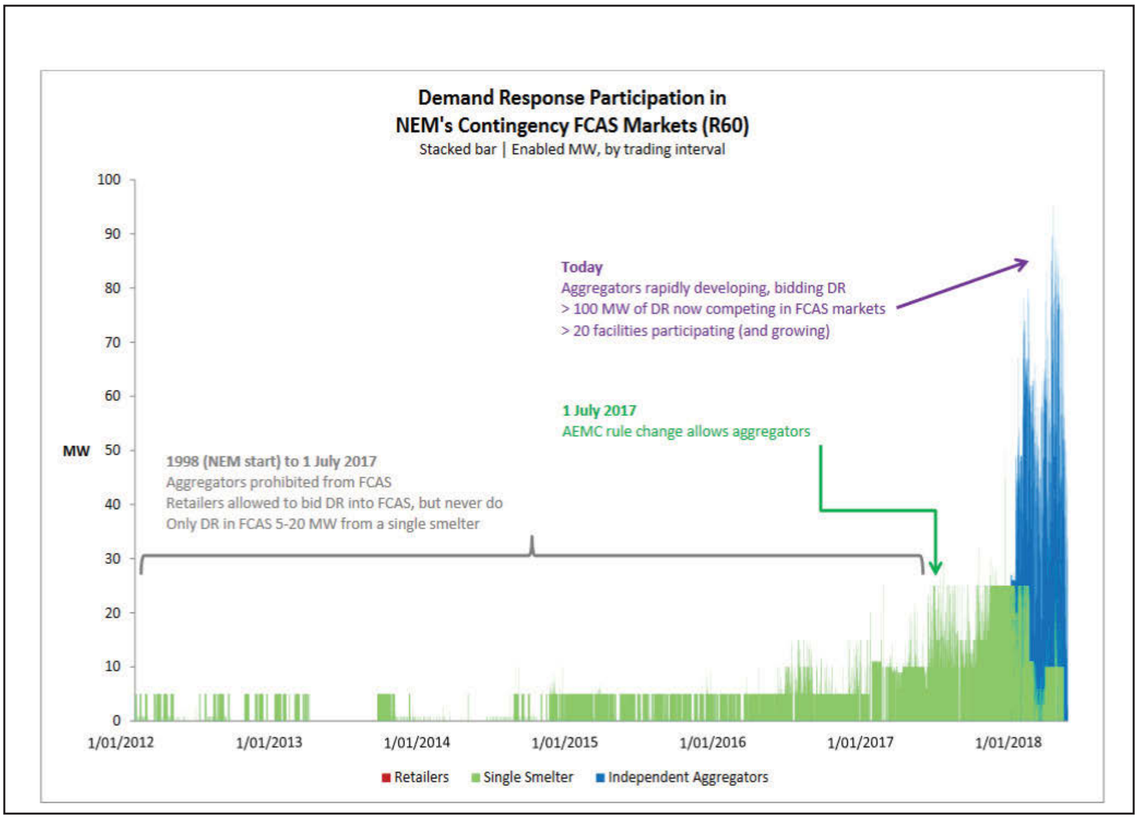

Figure 8-15 Impact of allowing DR aggregators into the NEM FCAS market (post July 2017) (Renaud, 2018)

System restart ancillary services (SRAS) involve providing generation output to restart the electricity system in case the entire system shuts down. However, DR is not a practical resource for this form of ancillary service.

Recommendation G10: *AEMO should continue to monitor and report on the performance of Demand Response in Frequency Control Ancillary Service and encourage the use of decentralised energy for other purposes in the NEM.*

Strategic reserve

Another key question in the context of setting objectives for the national electricity pool relates to the question of reliability. This particularly relates to supply adequacy, which is a function that is shared between the market and the centralised institutions of the market, particularly the Australian Energy Market Operator (AEMO). AEMO has ultimate responsibility to ensure adequacy of supply.

This issue has recently come to the fore as the longstanding surplus of generation capacity in the National Electricity Market has given way to potential shortfalls, particularly as a result of coal fired power stations closing. Over the last six years, ten coal fired power stations in the NEM have closed (Dunstan et al., 2017, p.17). A further nine coal power stations, accounting for 50 percent of Australia's coal fired power station capacity are expected to reach the end of their economic lives over the next 15 years (Dunstan et al., 2017, p.18).

It should be noted that lack of generation capacity has not been a significant issue in the NEM since it was created in 1998. As illustrated in Figure 8-16, generation adequacy has only been a cause in 1.2 per cent of supply interruptions in the NEM between 2005 and 2010.

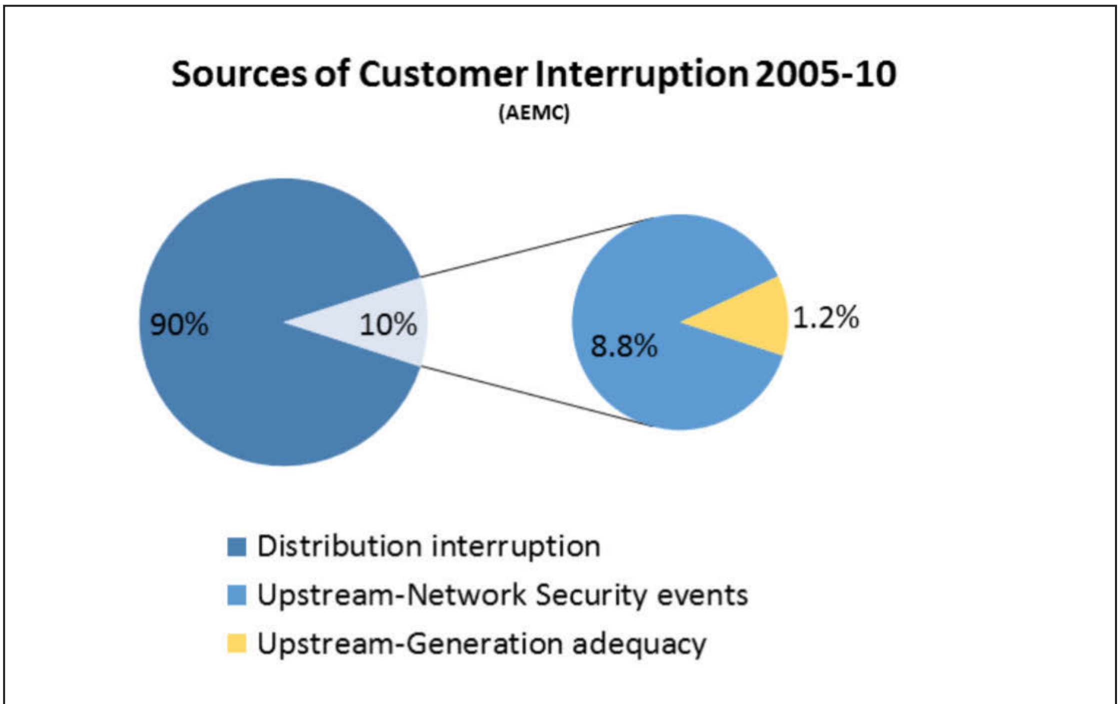

Figure 8-16 Sources of customer interruption

(AEMO's submission to the Finkel Review, cited by PIAC, 2017)

The National Energy Guarantee has been proposed as a policy response to ensure a strategic reserve of generation capacity, but it remains to be seen whether this is will be (or will be allowed to be) an effective response. In any case, it is crucial that DM and decentralised energy are allowed to compete fairly in providing such resources.

Recommendation G11: *Commonwealth, state and territory governments should ensure that, if the Reliability Guarantee or an alternative mechanism is adopted to provide strategic reserve capacity for the NEM, then DM and decentralised energy should be allowed to compete fairly in providing this capacity.*

Renewable Energy Target

One of the principles of least cost competition is that all relevant costs should be taken into account. Although, the NEO has been established as notionally technology neutral and environmentally blind, in practice the market has been heavily influenced by technology-specific, environmentally-driven policy ever since it was established. A case in point is the several iterations of the renewable energy target. In 1997, the Howard Government adopted a Mandatory Renewable Energy Target (MRET) which aimed to increase the share of Australia’s electricity that came from renewable sources by 2% (from 10.5% to 12.5%) by 2010. This target evolved into a 20% Renewable Energy Target by 2020 (RET) under the Rudd Government in 2008, and most recently a de facto 23.5% target by 2020 under Prime Minister Abbott in 2015.

Consequently, this environmentally motivated renewable energy policy measure has now stimulated much more new generation capacity than has the operation of the NEM itself. Moreover, renewable generation is now cheaper than the new fossil fuel-based technologies that the NEM was expected to facilitate at lowest cost! This highlights that such ‘environmental’ matters must be considered and managed by the NEM and its institutions.

The Federal Government is now considering what policy mechanism will replace the RET in the period 2020–2030 in the context of the National Energy Guarantee (NEG) and the Emission Guarantee in particular.

Recommendation G12: *Commonwealth, state and territory governments should ensure that demand management and decentralised energy are fully considered and incorporated in developing renewable energy and carbon abatement policy* *instruments, such as the proposed emissions guarantee under the National Energy Guarantee.*

Pricing

Based on the great fluctuations in prices in the generation market pool, there appears to be a very strong need for pricing to reflect costs. This is, of course, the whole point of the bidding process for the pool.

However, there have been numerous occasions when the competitiveness of the National Electricity Market generation pool has been called into question in particular jurisdictions of the NEM, such as South Australia.

This demonstrates that simply establishing a competitive market mechanism does not necessarily *deliver* effective competition. It is also essential that there are sufficient players in the market to ensure effective competition. This raises the issue of market concentration and market power and their impact on effective competition.

The issue of market power has been the subject of numerous reviews and investigations by the Australian Competition and Consumer Commission (ACCC) and others (AEMC, 2017c). Related to this question of market power and market concentration, is the vertical integration of generation and retailing in the Australian market with the three same companies dominating both the generation market and the retail market.

8.5 Least cost competition in networks

This thesis, particularly Chapter 2, has emphasised the importance of networks in ensuring a low-cost and efficient electricity system. Networks represent the largest share of electricity costs, prices and bills in Australia. As shown in Figure 8-17, networks can account for 'around 40 to 55 per cent' of residential retail electricity prices, while 'wholesale' costs (including generation and retail margins) contribute 30 to 40 per cent of the price (AEMC, 2017, p. ii).

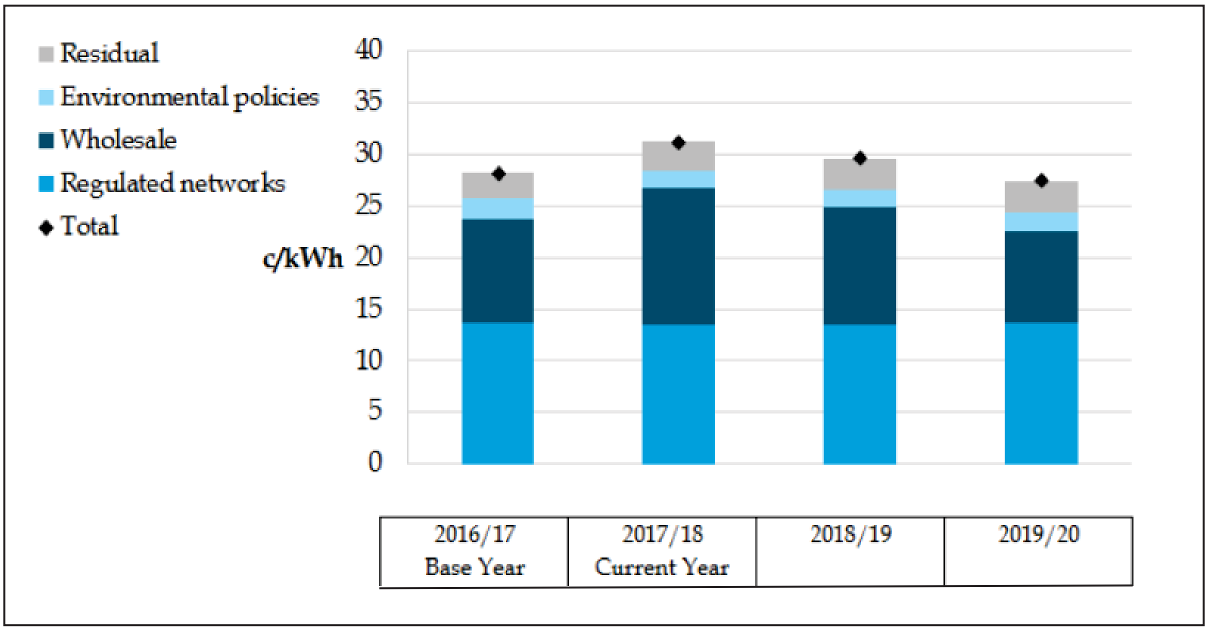

Figure 8-17 Trends in national residential electricity cost components
(AEMC, 2017)

The networks therefore comprise the most significant segment of the national electricity system, and are worthy of most attention in ensuring least cost outcomes. Despite this pre-eminent role, the networks have tended to be overlooked.

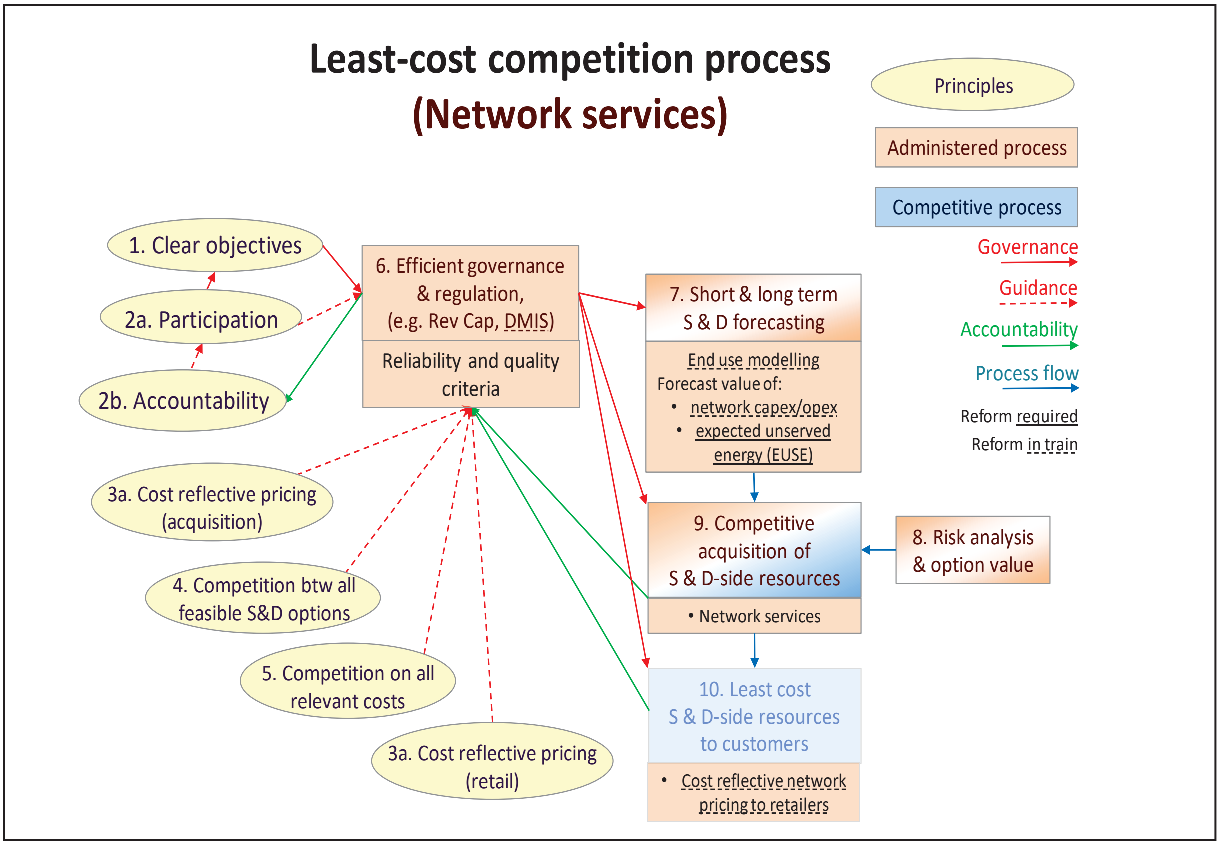

Figure 8-18 Least cost competition in the network services segment

Networks include:

- the *transmission network* that moves electricity at very high voltage (typically 132kV to 500kV) over large distances and interstate, from large centralised generators to load centres
- the much more extensive *distribution network* that transports electricity at lower voltage (typically less than 132 kilovolts) and delivers it to customers' premises.

As networks remain centrally planned regional monopolies, they are amenable to a traditional least cost planning approach. However, planning is only one of several functions of network businesses.

The key functions of electricity network businesses that are crucial for the purposes of least cost outcomes include:

- network ownership
- network operation
- network planning
- resource procurement.

These four key network functions are discussed below in the context of supporting least cost outcomes and applying least cost competition principles.

When the incentives for these four functions are not aligned, it can lead to inefficient outcomes. Some critics have argued that some of these functions (such as ownership and planning) are intrinsically in conflict, and so should be organisationally separated. This is the case in Victoria, where transmission network ownership (by AusNet Services) has been separated from transmission network planning (which is the responsibility of AEMO).

However, as is argued below, the potential conflicts relate to the incentives associated with each function, rather than to the functions themselves. To separate functions is costly and time consuming, and if incentives are not corrected, then the problems are likely to persist in any case.

8.5.1 Network ownership

The function of ownership is closely tied to the objectives of the network businesses, and in particular the objective of generating a financial return to shareholders. There is a range of ownership structures for network businesses within the NEM. They range from pure government ownership in Queensland and Tasmania, to joint ownership in the ACT, to a mix of partial private ownership, public ownership and full private ownership for some network businesses in NSW, to full private ownership in Victoria and South Australia.

While there are numerous variations in the performance, costs and levels of public engagement of these network businesses, it is difficult to discern any consistent relationship between the form of ownership and these outcomes. What is consistent across the network businesses is a requirement to deliver a strong financial return to shareholders (either private or government) and the delivery of such a return. In other words, the managers of network businesses have a strong objective and incentive to deliver a profit to (private or public) shareholders and they clearly place a high priority on meeting this objective. Indeed, the remuneration packages of the senior executives are often dependent on delivering a strong financial return to shareholders.

Regulatory incentives and ‘revenue decoupling’

Given that delivering a strong financial return to shareholders is a primary goal of the managers of the network businesses, the factors and behaviours that will fulfil this goal will have a powerful impact on whether least cost outcomes are pursued and achieved. A strong financial return depends on generating a profit, which in turn depends on maximising revenue and minimising costs. Given that the network businesses are regulated monopolies in which revenue and cost depend heavily on the incentives created by the regulator, these regulatory incentives will have a strong impact on the behaviour of network businesses. If these incentives reward least cost outcomes, then least cost outcomes are likely to follow. If the regulatory incentives reward behaviour contrary to least cost outcomes, then a least cost outcome is unlikely.

For example, as discussed in Section 5.6.5, it is crucial that the regulatory incentives for the distribution network businesses clearly reflect an objective of providing a reliable network to convey electricity, whatever the throughput of electricity is, rather than an objective of maximising the throughput volume of energy. In other words, the revenue and profit of the network business must be de-linked, or ‘decoupled’, from the throughput volume.

This strategy is termed ‘revenue decoupling’ or simply ‘decoupling’; that is, it involves breaking the link between the revenue or profitability of the network business and the volume of electricity that is transmitted through the network (see also Section 6.5.1).

The first way in which decoupling can be achieved is by a revenue cap, rather than a price cap. The other is through an ‘electricity revenue adjustment mechanism’ (ERAM), which allows the utility to recover electricity sales foregone. Both of these mechanisms have been applied in Australia. The most recent development in this space is the introduction of the Demand Management Incentive Scheme (see Section 8.5.4 below).

Investment incentives, opex/capex and ‘gold plating’

While decoupling addresses the short-term incentives from year to year within a regulatory period, it does not address the longer-term incentives about investment, ‘rolling in’ investment into the ‘regulatory asset base’ and return on investment. Even if the network business’s profit is fully decoupled from sales volume and the business does not make any additional revenue or profit from additional throughput (see Section 6.5.1), it will not be in the financial interest of the network business to support DE if the returns on investment in network infrastructure are more attractive. Where the allowed regulated returns on capital investment exceed the cost of capital, there will be an incentive to overinvest in capital, or ‘gold plate’ the network.

The past decade has seen unprecedented levels of investment in monopoly electricity networks approved by regulators in NSW and Queensland, as illustrated in Figure 8-19. For example, over the 2005–09 period, these network businesses in the NEM were approved to spend $14.4 billion on capital expenditure, equivalent to about two-thirds of their total current asset value at that time. During the following regulatory period the forecast investment distribution networks alone grew to around $25 billion, compare to total asset value of around $39 billion (AER 2009b, p165).

While there is widespread public acceptance that the major cause of this rapid growth in network capex was excessive allowable return on capital and ‘gold plating’ of networks, this conclusion is contentious. In October 2012, the then CEO of the Energy Networks Association rejected the criticism:

> Gold plating is a cute term where someone has looked at some data to show that network expenditure has increased over five years compared to the previous five years … We’re in an industry where there’s a lot of outside variables that determine what your costs are and new

levels of capital expenditure, and there's also a historical cycle of government expenditure on infrastructure. If you take a long-term view you see cycles of investment, and cycles of under-investment' (Roberts, 2012).

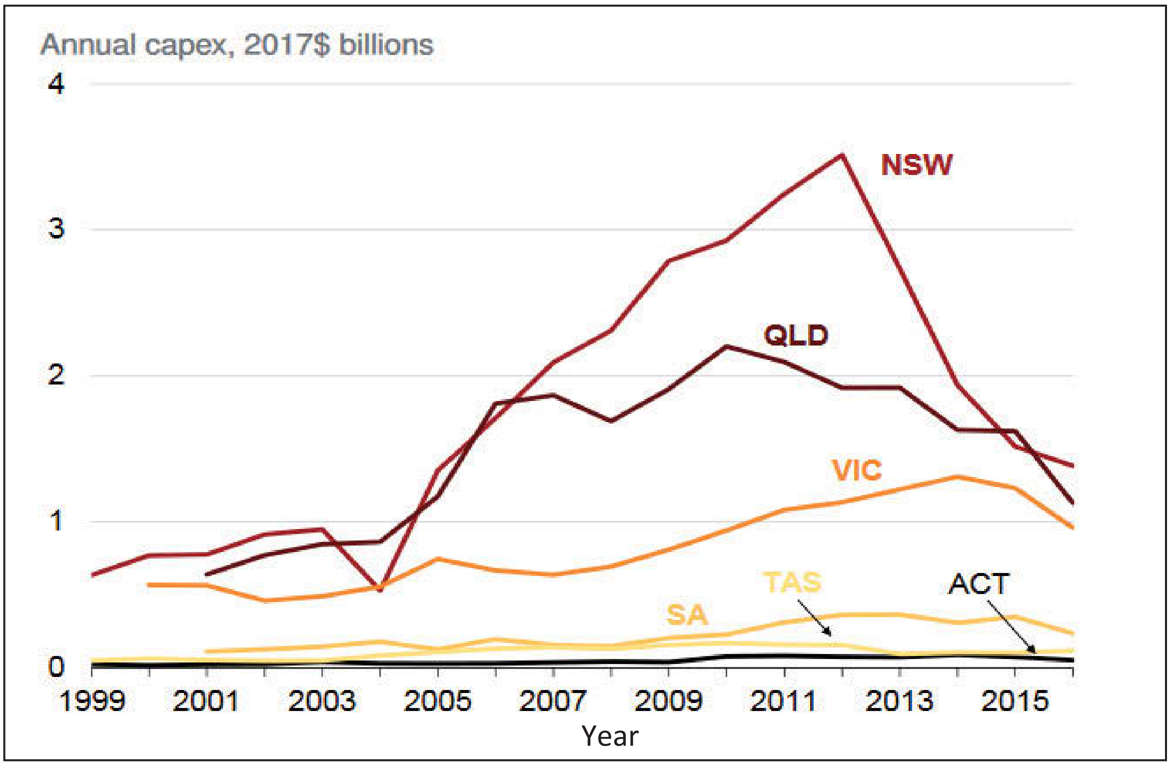

Figure 8-19 Distribution network capital expenditure (1999 to 2014)
(Wood et al. 2018, p. 13)

One key driver for the increase in network charges was the high allowable weighted cost of capital set by the AER was set in the wake of the Global Financial Crisis in 2007–08, when the market risk of lending was perceived to be very high. A second major driver was, as shown in Figure 8-19, very large increases in capex in NSW and Queensland. This surge in network capex was related to significant strengthening of the network reliability guidelines in these two states.

In Queensland, this lift in reliability standards was in response to high profile reliability problems in 2003–04, associated with a severe storm season, ahead of a Queensland state election in March 2004. The government responded by commissioning an inquiry led by Darryl Somerville (Independent Panel (Queensland Department of Natural Resources, Mines and Energy) 2003). The Somerville Inquiry recommended strengthening reliability standards, which were adopted by the Queensland Government in 2005 (AER, 2007, p. 53). The NSW Government, fearing similar reliability problems, strengthened reliability standards in 2005 through new licence conditions for distribution network businesses which set minimum network reliability standards that would need to be met by 2014 (AEMC 2012b, p. 1).

Some have suggested that these reliability standards were deliberately raised to inflate dividends to their government owners.

> The reason that the networks are spending up big on better infrastructure is not just because regulators let them, but also because they are forcing them to.
>
> That's not that surprising, because the owners of the networks and the key power-brokers in the regulatory system are the same entities: state governments. There's an obvious financial gain for state governments that can reap higher profits from state-owned utilities (Eltham, 2012).

Others have highlighted public ownership of the networks as a key driver of the increase in network charge. For example, Wood states,

> We estimate that up to $20 billion of investment in power networks was excessive, mostly in NSW and Queensland. There is little evidence of a similar problem in Victoria or South Australia. The main causes of over-investment were regulatory incentives and public ownership, and excessive reliability standards (Wood et al. 2018, p.1).

However, while there is clearly a correlation between public ownership, tighter reliability standards and rapid growth in capex, this does not establish causation. Those who seek to make this case would need to explain why the relationship only emerged *after* the controversial network reliability problems occurred in Queensland in late 2003. So, while the causes of the excessive capital expenditure on networks are contested, the fact that there was excessive expenditure, and the assertion that this was in response to regulatory incentives established by the Australian Energy Regulator and the government, are widely accepted.

The large capital expenditure was contrary to a least cost outcome for two reasons. Firstly, due to the regulatory incentives, more network capex was undertaken than was needed. Secondly, the regulatory incentives created a bias in favour of network capex and against opex, and in particular against DM opex, so that lower cost DM was overlooked as a means of meeting reliability requirements.

For both government and private shareholders, the imperative to maximise financial returns on network business is unlikely to subside. However, this imperative will not be an obstacle to least cost outcomes provided that the regulatory incentives facing network businesses are focused on rewarding least cost outcomes.

Recommendation N13: *Both short term and long terms incentives for the network businesses should be directed towards least cost outcomes for consumers. This includes:*

- *Short term: The form of regulation should maintain the recent reform to decouple network annual energy throughput from annual revenue and profit.*
- *Long term: The medium term regulatory determination should ensure that there is no incentive bias between capex and opex, or between network investment and DM options.*

The shift by the AER from price caps to revenue caps for distribution network businesses starting in NSW in 2014, has effectively achieve decoupling in relation to short term incentives (AER 2013, p. 43).

In relation to the long term incentives, the recently adopted Demand Management Incentive Scheme, (in concert with other reforms, such as adjustment to the WACC and the removal of limited merits review) has the potential to balance the incentives between capex and opex and between network and DM options.

Recommendation N14: *Commonwealth, state and territory governments should support the Demand Management Incentive Scheme with education, facilitation and thorough annual reporting in order for the Scheme to fulfil its potential to level incentives between network capital expenditure and DM operation expenditure.*

8.5.2 Network operation

While providing strong financial returns to owners is a major driver of network behaviour, it is not the only objective that the network businesses are required to meet. Many of the criteria of the national energy objective are very dependent on planning and operation of networks, particularly in regard to: safety, security, reliability and quality. This is particularly so as the distribution network is the source of most interruptions to supply, including interruptions due to storms.

In many respects, these criteria of safety, security, reliability and quality, are prescribed in a range of laws both within the electricity industry, including in the National Electricity Law and subordinate regulation, and more broadly in areas such as occupational health and safety and in response to a range of government priorities. Meeting these objectives is essential to the process of delivering least cost outcomes. The biggest influence on meeting these criteria is the need to match supply capacity to expected demand. Network businesses have a range of tools available which enable them to use existing network capacity to meet expected demand. These operational tools include: monitoring and maintenance, circuit and load switching, network pricing, connection policy, demand management and load shedding.

In many instances, these objectives can be met, in part or in full, by decentralised energy, at a lower cost than by the traditional network infrastructure measures. However, to date in Australia, there has been little reliance on DM and decentralised energy in network operation. Consistent with the least cost competition principle of considering all viable options and adopting the least cost mix of options, decentralised energy should play a much greater role in network operation. For example, in managing voltage and power factors on a distribution line, a distribution network business can rely on manual seasonal changes to distribution transformer voltage ‘tap settings’, or it can install ‘automatic tap changers’ to adjust voltage automatically, or it can install power factor correction equipment like capacitors and static VAR compensators. Alternatively, the distribution network could rely on demand management by offering incentives to customers served by the distribution line incentives to change their consumption behaviour or to use customer decentralised energy, such as solar PV or battery inverters to provide voltage support or power factor correction (Alexander D. et al., 2017).

This raises the question of what steps are required to encourage network businesses to use DM when it can provide a lower cost solution. The simple answer may be that in general, no additional steps are required which specifically address network operation, beyond the steps described in other parts of this chapter. Provided that the network businesses faces balanced regulatory incentives for DM and DE relative to network solutions, it will be in its interests to adopt DM solutions in its operations wherever they are lower cost.

However, there is one exception to this, where additional steps are required. This is discussed in the following section in relation to efficient network pricing.

Efficient network pricing

Consistent with the least cost competition principle of cost-reflective pricing, a key element in ensuring least cost operation of networks is efficient pricing.

As noted in Sections 5.6.4 and 6.6.2 (Policy Tool 5), network pricing generally very poorly reflects costs, particularly once they are incorporated into retail tariffs. A key reason for this is that currently approximately 70% of Australia homes and businesses have simple 'accumulation meters', that is, meters that only record the total electricity consumption since the last meter reading, typically every three months (Energy Networks Australia, 2017). Such meters do not allow time variable tariffs. Even in Victoria, where 2.8 million accumulation meters were replaced via a comprehensive smart meter rollout between 2006 and 2014, most consumers are not on time-of-use tariffs (Victorian Government, 2015).

Consequently, the large majority of electricity consumers in Australia are subject to very blunt pricing structures that generally simply include a daily supply or standing charge, typically of about $1 per day and a fixed per kilowatt hour price, typically of about $30 cents per kWh (see for example, AGL 2018). Such flat tariffs provide little incentive for customers to reduce demand at peak times. Consequently, peak demand is higher than it would otherwise be, and expensive network and generation infrastructure is built to service this peak demand. These costs then lead to higher electricity bills for all consumers.

Even where time-of-use network charges are applied, they are generally not very cost reflective. They generally consist of a relatively flat 'peak/off peak', or 'peak/off-peak/shoulder' structure with a fixed daily access charge. Larger business customers usually have more cost-reflective tariffs, but even these seldom include a dynamic peak price that provides a strong incentive for customers to reduce demand at times and in places of expected network peak or constraint.

Efficient network tariffs would have a more dynamic character. That is, they would be significantly high at times of constraint and lower at other times when no such constraint prevails.

Recommendation N15: *Network business should adopt more cost-reflective electricity tariffs. This should include working with retailers and other third parties to provide innovative offerings combining smart meters, time-of-use tariffs and support for* *decentralised energy that can deliver lower bills for consumers and reduced net costs for network businesses, focusing on areas of network constraint.* (This is particularly relevant in Victoria, where smart meters are already widespread. The DMIS could assist in this.)

Recommendation N16: *Regulators, policy makers and customer advocates (such as Energy Consumers Australia) should assess and promote the potential for more cost-reflective pricing (and complementary decentralised energy) to deliver lower costs outcomes for consumers.*

Recommendation N17: *Commonwealth, state and territory governments should work with network businesses, retailers and customer and welfare representation to develop innovative flexible pricing and incentive options to give disadvantaged electricity customers access to the benefits of time-of-use tariffs, while protecting them from significant adverse impacts on bills.*

8.5.3 Network planning

The third key function of network business is planning to ensure the provision of adequate, safe, secure and reliable networks. Given that the network segment is (and for the foreseeable future will remain) a centrally planned, regulated monopoly, it would seem to be a prime candidate for least cost planning. While LCP has never been explicitly adopted in the NEM, the network businesses are nominally subject to planning provisions similar to least cost planning principles and a least cost mix of demand- and supply-side resources. For example, in relation to distribution networks, the National Electricity Rules state:

> ...the *Network Service Providers* affected by the RIT-D project must ensure, acting reasonably, that the investment required to address the identified need is planned and developed at least cost over the life of the investment (AEMC, National Electricity Rules version 106, s. 5.17.3 d).

There is a similar provision in relation to transmission networks, although 'least cost' is not defined in the Rules in either case.

Each distribution network business must also publish a Distribution Annual Planning Review and a demand-side engagement strategy for: (1) engaging with 'non-network' providers; and

(2) considering DM and decentralised energy options (AEMC 2018b). In total, there are 39 references to how network businesses should consider and engage with non-network (DM) options in Chapter 5 of the National Electricity Rules. These reflect numerous changes to the NER in relation to DM since the NEM was established in 1998. One of the most prominent of these rule changes was the establishment of the Regulatory Investment Tests (RIT-D and RIT-T) as discussed in section 8.5.4 below.

Despite these ostensibly pro-DM provisions in the National Electricity Rules, there has been relatively little DM undertaken by network businesses in the NEM (as discussed in Chapter 3). On the other hand, while the National Electricity Rules may not drive DM activity, they arguably provide ample scope for DM to be pursued if the network businesses are motivated to do so. This highlights the importance of incentives rather than rules in driving network business behaviour. This also suggests that the most recent rule change relating to DM may be more effective than previous ones, because it is focussed on incentives rather than obligations. The Demand Management Incentive Scheme Rule change, which was adopted in 2015, is intended to redress disincentives to undertaking DM (AEMC 2015).

Forecasting

As they are local monopoly service providers, each network businesses has an obligation to provide sufficient network capacity to meet the needs of the service territory and community that it serves. Accordingly, network businesses have an obligation to undertake accurate and credible short- and long-term supply and demand forecasting

This forecasting is generally focused on identifying periods of peak demand as this is the key driver of both reliability and expenditure by the network businesses. However, there are other dimensions that are also important. Increasingly, minimum demand has become an issue, as has reverse flow in the context of local, mainly solar PV, generation and the shift away from a radial to a meshed industry structure.

The next aspect of the network planning discussed here is forecasting network constraints associated with anticipated changes in demand and supply conditions, and then estimating the cost of the network infrastructure required to address these constraints.

8.5.4 Network resource procurement

The fourth key function of network businesses is resource procurement and acquisition. Traditionally, network constraints have been addressed by expenditure on network infrastructure. However, in the context of least cost competition, it is crucial that both supply- and demand-side solutions to network constraints are considered.

The combination of network functions of ownership, planning and procurement creates the potential for real and perceived conflicts of interest (as discussed in Section 8.5.1). This arises when the network business determines the need for the investment, and then subsequently becomes the owner of the asset and earns a financial return on this investment.

In order to address the potential bias in planning and developing the network, distribution and transmission businesses are required to undertake a 'regulatory investment test'. For example, the Regulatory Investment Test for Distribution (RIT-D) requires a distribution network business to investigate DM (or 'non-network alternatives') before augmenting its network.

As noted above, the RIT-D states:

> the *Network Service Providers* affected by the RIT-D project must ensure, acting reasonably, that the investment required to address the identified need is planned and developed at least cost over the life of the investment (National Electricity Rules (version 70, s. 5.17.3 (d))

On the face of it, this reflects the LCP principle of considering all relevant options. However, this provision does *not* apply under the following circumstances:

> (1) the RIT-D project is required to address an urgent and unforeseen network issue that would otherwise put at risk the reliability of the distribution network …;
> (2) the estimated capital cost to the Network Service Providers affected by the RIT-D project … is less than $5 million …;
> (3) the cost of addressing the identified need is to be fully recovered through charges other than charges in respect of standard control services …;
> (4) the identified need can only be addressed by expenditure on a connection asset which provides services other than standard control services …;
> (5) the RIT-D project is related to the maintenance of existing assets and is not intended to augment a network or replace network assets; (AEMC, NER version 106, 5.17.3 (a))

Of these exclusions, the $5 million minimum investment cost threshold for applying the RIT-D is probably the most significant, because most network investment is in projects below this cost threshold.

However, there are other barriers associated with the RIT-D process which have discouraged least cost outcomes, including:

1. The requirement to assess non-network alternatives only arises *after* the distribution network business has already identified and developed a network solution, thus creating significant momentum within the network business to proceed with network solutions, particularly when the network business has already invested in a site or easement for the network solution.

2. The consideration of non-network alternatives often occurs so late in the process that there is often insufficient time to assess and implement DM without excessive perceived risk.

3. DM measures are often most cost effective at a smaller scale, and therefore at an earlier stage than the network option. The failure to consider or implement non-network alternatives at this earlier stage reduces their viability.

4. The structure of the economic regulation of distribution network businesses means that network investment is generally more profitable than DM (Dunstan et al. 2017). For example, network investment generally allows distribution network businesses to earn a return on investment, while DM can generally only recover costs. Also, distribution network businesses can generally include recovery of capex in the regulatory determinations, while DM is generally seen as being recovered out of avoided capex.

It is therefore not surprising that few RIT-Ds have led to DM options being selected, and the level of network DM activity remains low (see Chapter 3).

This highlights a very significant but little noticed bias in the context of network development. The trigger for proposed investment to address network constraints is generally based on the point in time at which the expected cost of the impact on supply reliability (in terms of expected unserved energy - USE) *exceeds the cost of investment in new network infrastructure*, rather than the point at which the expected cost of the impact on supply reliability exceeds the cost of demand management.

The distinction here is important, because DM is generally cost-effective at a much smaller scale than network investment. This means that it may be cost-effective to use DM to address an emerging network constraint well before the point at which it would be considered justified to address the growing constraint with a traditional network infrastructure solution.

Therefore, in reporting forecast demand and potential network constraints, it is *important that the expected unserved energy* is considered. It is crucial that these data are reported and quantified in value terms, rather than simply identifying constraints that can be addressed by network solutions.

The procurement of demand-side and supply-side resources to address network constraints is an area where greater competition can offer great value to the network businesses, and consequently to their customers.

Traditionally, there has been a level of competition in the acquisition of supply-side resources in the sense that many of these services and products are competitively tendered out, so that providers compete to deliver the least cost solution to the network business.

However, in order to maximise competition and efficiency, it is crucial that this process of competitive procurement of resources is extended to the widest range of competition available, and in particular that it is extended to demand-side resources as well supply-side resources.

In doing this, it is important that those responsible for the procurement of resources undertake this process in a way that is amenable to effective competition, recognising that the demand-side resource providers have different characteristics, including different economies of scale, to those of supply-side resource providers.

Reforming network incentives: The DMIS

The National Electricity Law (NEL) and the National Electricity Rules (NER) are important determinants of what is considered acceptable behaviour by network businesses in relation to DM and least cost outcomes. There is a strong case for changing both the NEL and the NER to facilitate least cost outcomes for network businesses. However, there is already scope for much greater uptake of cost effective DM within the existing NEL and NER. This suggests that the regulatory incentives that the networks operate under have a greater influence than “the letter” of NEL and the NER in frustrating the development of cost effective DM.

Following many years of advocacy and research, including in the context of this doctoral research (see Section 9.2), a recent reform has been instituted that has the potential to redress these perverse regulatory incentives. This is the reform of the Demand Management Incentive Scheme (DMIS).

The impetus for the reform of the DMIS arose at the height of the network ‘gold plating’ controversy in 2012. The same 2012 AEMC Power of Choice Review that recommended the Demand Response Mechanism (DRM) recognised that regulatory incentives faced by network businesses are crucial to the development of an efficient DM market (AEMC, 2012a). Accordingly, the AEMC proposed changing the National Electricity Rules to strengthen such incentives, recommending:

> [Recommendation] 18. Reform the application of the current demand management and embedded generation connection incentive scheme in the NER to provide an appropriate return for DSP projects which deliver a net cost saving to consumers. This includes creating separate provisions for an innovation allowance (AEMC 2012a, p. iii).

This led to two similar rule change proposals from the COAG Energy Council and the Total Environment Centre, which were merged into one proposal. This rule change was adopted by the AEMC in 2015, giving the AER responsibility for creating an effective DM Incentive Scheme and Innovation Allowance (AEMC 2015). Following this rule change, the Australian Energy Regulator (AER) split the then Demand Management and Embedded Generation Connection Incentive Scheme (DMEGCIS) to create two schemes: the Demand Management Incentive Scheme (DMIS) and the Demand Management Innovation Allowance (DMIA).

To support the AER in developing the new DM Incentive Scheme, the Australian Renewable Energy Agency (ARENA) commissioned the Institute for Sustainable Futures at UTS (ISF) to undertake a detailed study (which I led) to quantify the financial barriers to DM created by existing economic regulatory incentives for distribution network businesses.

In particular, this *Demand Management Incentives Review* considered how efficient and balanced the networks’ regulatory incentives were. As noted in the Review:

> Where regulatory incentives are efficient and balanced, the network business should achieve higher net profits if they undertake measures that deliver higher net benefits to their customers. If regulatory incentives are inefficient and biased against DM, a network business may receive a lower net profit from a DM solution that would deliver a higher net benefit for customers. (Dunstan et al. 2017, p. iii)

The Review was intended to identify and quantify economic regulatory barriers to network businesses transitioning towards a more decentralised and service-oriented business model and to recommend appropriate incentives to address these barriers. The key findings from this Review included:

> 1) In distribution network regulation, there are currently significant barriers to implementing cost effective DM. These barriers include:
>
> a) Recovery of DM operating expenditure (opex) is treated less favourably than recovery of non-DM network opex, and less favourably than network capital expenditure (capex) and;
> b) There is a bias in favour of network capex, relative to DM and other opex; and
> c) Future 'option value' is generally excluded when considering DM solutions.
>
> All three barriers are important, but the first appears to be the most significant. (Dunstan et al. 2017, p. iii)

The review concluded that:

> To correct for these inefficiencies in regulatory settings, an effective DM Incentive Scheme should be applied…
>
> … a [DM Cost uplft] should be set in the range 40% to 90% of the DM cost to the distribution network business.' (Dunstan et al. 2017, p. iv)
>
> … Payment of the DM incentive to a network business should be contingent on the network business publicly demonstrating a net benefit to customers
>
> … While this Review's scope included only the impact of economic regulatory incentives, there are other important non-regulatory drivers and potential biases in the decisions of distribution network businesses. These relate to network businesses' culture, conventions, expertise and risk management. (Dunstan et al. 2017, pp. iv-v)

The foundation of the Review was a complex spreadsheet model. The review explained that:

> This model analysed how current AER regulations impact on the financial incentives for network businesses in choosing between network investment and DM solutions. In other words, the model examined how network and DM solutions to network constraints impact on network businesses' costs, revenues and profits. (Dunstan et al. 2017, p. v)

The Review considered four different network constraint cases, with one network infrastructure solution and one DM solution for each. The four cases were selected based on advice from a diverse stakeholder reference group and they are set out in Table 8-1.

Table 8-1 Network constraint cases considered in the DM Incentives Review model

Case	Network Constraint
1	Urban regional high voltage (HV) cables, reaching end of service life
2	Over- and under-voltage on distribution feeder
3	Distribution zone approaching capacity on urban fringe
4	Unreliable distribution feeder to community on rural fringe-of-grid

(Dunstan et al, 2017, pp. 9-10)

The review analysis found, as illustrated in Figure 8-20, in Case 1 for the 30-year horizon, the DM opex solution delivers lower costs and higher net benefits ($128.3 million) to customers than the network capex solution ($92.8 million). If the regulatory system was working efficiently, then the network business should be incentivised to adopt the DM solution to the network constraint. However, from the network business's perspective, the network capex solution is the more profitable option ($44.6 million net profit compared to only $25.8 million net profit for the DM opex solution).

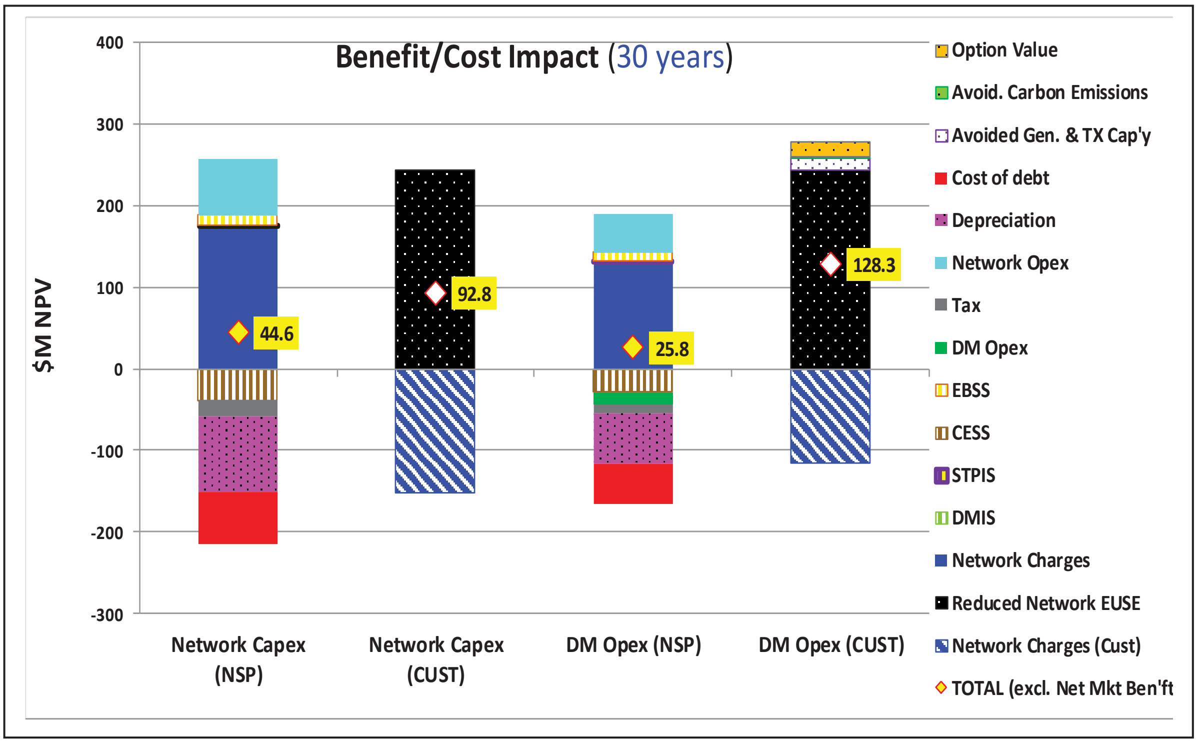

Figure 8-20 Network capex vs. DM opex benefit-cost analysis

(Case 1: 30 year perspective, without DM full cost recovery) (Dunstan et al, 2017, p.11)

If return on equity for the network business is considered as the decisive parameter instead of net profit, this also favours the network capex solution (4.9%), compared to the DM opex solution (4.7%) (Dunstan et al., 2017, p. 12).

This analysis was influential in the AER's deliberations in developing the DMIS. The AER announced the final form of the new Demand Management Incentive Scheme (DMIS) and the Demand Management Innovation Allowance (DMIA) in December 2017. The DMIS allows the network business to charge its customers a 'cost up-lift' of up to 50% of the cost of the DM implemented, where it is shown that there is a net benefit for consumers. The DMIS is also subject to the total additional charges not exceeding 1% of the maximum allowable revenue for the network business. Assuming that the network business fully adopts the DMIS at the maximum uplift of 50%, this could mean a total expenditure on DMIS-related network DM of about $1 billion over five years.

Provided it is well implemented, the DMIS reform offers the best chance in the history of the Australian electricity supply system to facilitate widespread, efficient and cost-effective DM by distribution network businesses.

According the 2015 rule change by the AEMC, the new DMIS is currently due to start at the beginning of the next regulatory period in each NEM jurisdiction (AEMC 2015). The change would take effect on 1 July 2019 in NSW, the ACT and Tasmania and on 1 January 2021 in Victoria. However, the AER has subsequently received approval for a further minor rule change to allow the DMIS to commence earlier than this, and potentially as soon as late 2018.

Key recommended least cost competition reforms for network businesses are:

Recommendation N18: *Distribution network businesses should take full advantage of the Demand Management Incentive Scheme (DMIS) in order to pursue cost-effective DM. This includes seeking to start the DMIS at the earliest opportunity, ramping it up to the fullest extent possible and encouraging industry-wide coordination.*

Adopting the DMIS in this way will not only be profitable for DNSPs in its own right, but will also position DNSPs to develop their business opportunities in the expanding DER space, and build social capital by facilitating the delivery of cleaner, lower-cost energy services.

Recommendation N19: *The AER should actively support effective DMIS implementation. This support should include ensuring aggregated, standardised comparative reporting of distribution network business performance, including costs and benefits to consumers, highlighting best practice, and encouraging knowledge sharing.*

Recommendation N20: *The AER should make clear that it considers it prudent for a network business to undertake DM when the net cost of DM is less that the associated avoided cost to consumers of reduced expected unserved energy.*

Undertaking DM in this context leads to a lower expected cost to consumers. This is consistent with a least cost objective. Network businesses, DM providers and consumer representatives should collaborate with the AER in implementing this approach.

Recommendation N21: *The Australian Energy Regulator should ensure consistent, consolidated annual reporting of network DM performance. This should include comprehensive reporting of impacts, outcomes, benefits and costs. This should include DM undertaken both within and outside the DMIS and price-based and non-price-based DM.*

Recommendation N22: *Commonwealth, state and territory governments should facilitate knowledge sharing on network DM activity between network businesses, DM providers, customer representatives and policy makers.*

8.6 Least cost competition and the retail electricity market

The third major segment of the electricity supply industry is the retail market. While this segment is generally much smaller than the generation and networks segments in terms of assets, infrastructure share and electricity bills, it is also very influential in that it represents the key interface between the industry and consumers. The structure of this retail system for the purposes for least cost competition is summarised in Figure 8-21.

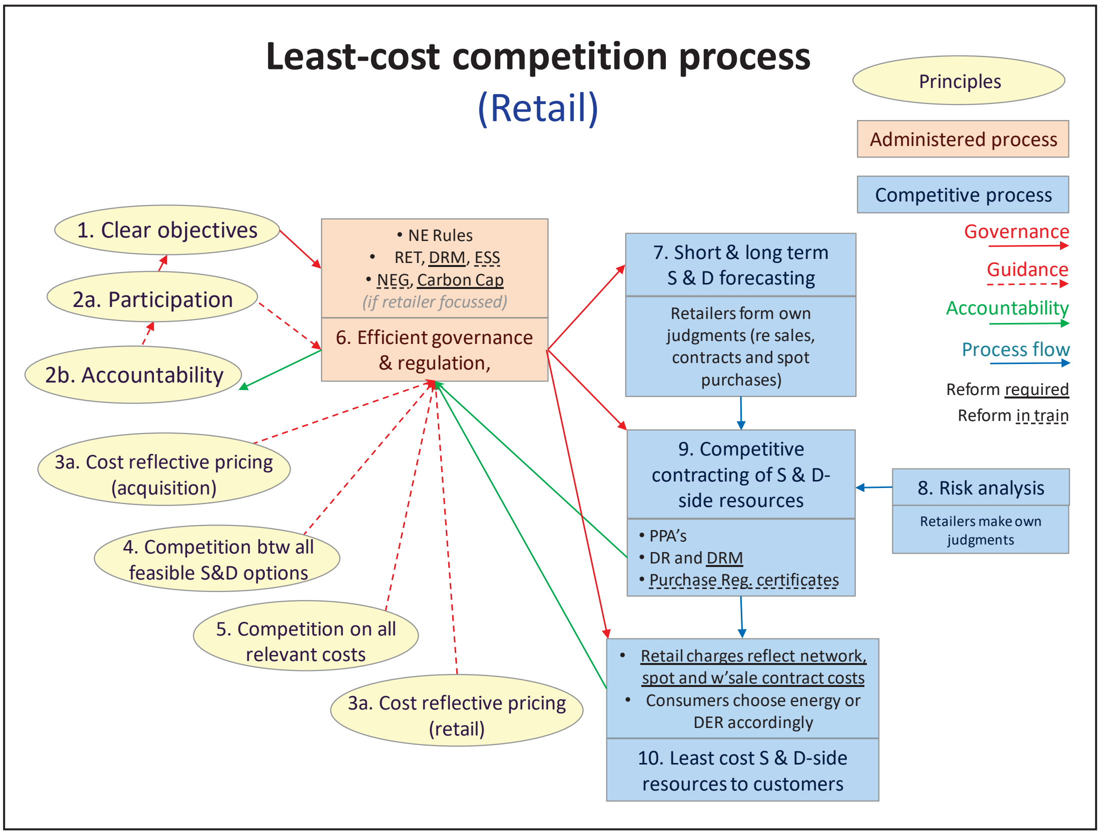

Figure 8-21 Least cost competition in the retail market segment

The key components of the retail segment of the electricity system in this context are:

1. retailer involvement in the wholesale spot market, between generators and retailers
2. retailer involvement in the wholesale contract market
3. the retail market and retail pricing between retailers and customers
4. complementary regulatory retail markets (such as the RET market and the Energy Efficiency Obligation (EEO) market).

These components are discussed below.

8.6.1 Retailer involvement in the wholesale spot market

The engagement of electricity retailers in the wholesale spot market for generation is in many ways the mirror image of the engagement of the generators. This is for two reasons. Firstly, as discussed in Section 8.4 above, the dominant players in the retail market are also the dominant players in the generation market, the so-called large gentailers.

Secondly, prices in the spot market have opposite impacts on retailers and generators. Whereas a retailer generally seeks to avoid exposure to high pool prices, the generator will generally gain from high pool prices, either directly or indirectly via the upward pressure that high pool prices place on contract prices. Of course, the actual incentives will depend on their contract positions.

The relevance of the retailers' engagement with the spot market is twofold. Firstly, it raises the question of demand management, particularly the uptake of demand response (DR) and the impact or DR on pool prices as a competitor for generators (or gentailers), who are seeking to maximise prices in the wholesale market. Secondly, it has implications for other decentralised energy options, which impact less on high pool prices and more on the volume of electricity supplied at the retail level. This includes the impact of energy efficiency and distributed generation such as solar PV.

Retailers' incentives should in principle generally align with customer interests, in the sense that both should be seeking to avoid exposure to high pool prices. In this context, demand response is a mutually beneficial solution. Indeed, some electricity retailers are actively developing their capacity in this area for competitive advantage. The electricity retailer Flow Power is a good example of this. Flow Power deliberately maintains an exposure to spot market prices, which Flow Power passes on to its customers (Flow Power 2018). Instead of seeking to hedge its spot exposure via the physical hedge of owning generation, or purely via a financial hedge through a cap or swap or alternative financial arrangement, it also hedges its own and its customers' risk by tapping the DR capacity of its customers to reduce demand at times of peak spot prices.

On the other hand, retailers who have more generation capacity than their retail demand, and consequently have a potential interest in higher pool prices, are less likely to seek to develop this part of the market. As noted in Section 8.4, the large incumbent retailers (gentailers) have generally resisted proposed reforms which aim to open up the DR market.

More recently, Snowy Hydro, the NEM's fourth-largest gentailer, has described demand response and wholesale demand management as 'untested' and a 'costly' alternative to traditional dispatchable generation (Potter 2018). *Provided there is effective competition* in the marketplace, then established market participants "talking their book" and defending their commercial interests in this way is to be expected and should not be a problem. However, *there **is** a concern about how effective competition is at present,* and given that Snowy Hydro is government owned, this is a threat to unbiased policy. The opening up of the demand response market to third party DR aggregators would assist in developing competition in this part of the retail market. (See Section 8.4.1.)

Recommendation R23: *The AEMC should support allowing Demand Response to be bid into the spot electricity market from customers separately from the host retailer, as proposed by the Finkel Inquiry (2017), the AEMC (2012) and the Parer Inquiry (2002).*

8.6.2 Retailer involvement in the wholesale contract market

As discussed in Section 8.4.2 in relation to the wholesale (generator-retailer) contract market, despite their very different forms, the spot market is closely entwined with the contract market. In practice, retailers manage their spot and contract markets together, so the discussion in the preceding section about the retail spot market is also relevant to the contract market.

However, there is another dimension to the contract market for retailers: power purchase agreements (PPAs). A PPA is essentially a legal contract on the part of a retailer or a customer to buy the power produced from a generator over an extended period. Retailer and/or customer PPA's are often essential to securing project finance in order to build new power stations. In the current context, where most new generation capacity is renewable wind or solar powered capacity, securing a PPA is crucial to new projects proceeding.

Retailers need both the volume of energy stipulated and for this energy to be available at the stipulated time of demand. If a renewable energy generator cannot provide this firm capacity or 'firmness', then, in order to manage exposure to the spot market, the retailer must secure this firm capacity from other sources, such as dispatchable generators, energy storage or flexible demand such as demand response. If the market is functioning efficiently, this should also encourage time-of-use pricing.

As coal-fired power stations are closing and being replaced by variable output renewable power stations, there is an increasing need to replace firm capacity as well as energy. This raises the question of how DE can fill this need for firm capacity.

Recommendation R24: *Retailers should embrace the transition toward renewable energy and seek opportunities to use DM and decentralised energy to complement supply from variable output renewable energy.*

Recommendation R25: *Commonwealth, state and territory governments and AEMO should research and promote the potential of DM and decentralised energy to provide firm capacity, and capacity firming services.*

8.6.3 The retail market and retail pricing

Electricity retailers have little influence over most of the fundamental criteria of the National Electricity Objective, such as, the safety, security, reliability and quality of electricity supply. However, retailers do have the primary relationship with consumers within the electricity supply industry. This relationship includes marketing, pricing, contracting, billing, inquiries and complaint management, and information provision.

Retailers therefore have a critical role in facilitating least cost outcomes for consumers. For example, retailers strongly influence total electricity costs through the structures of retail prices that they set and offer to their customers. If even a small proportion of the large swings experienced in wholesale spot prices were reflected in retail prices, this would significantly reduce peak demand and thereby reduce the need for expensive peak generation capacity by billions of dollars. Similarly, if cost reflective network pricing were to be passed on to retail customers, this could similarly cut network costs by billions of dollars. The potential benefits of more efficient cost-reflective pricing were recognised by the AEMC in its 2012 Power of Choice Review, as illustrated in Figure 8-22.

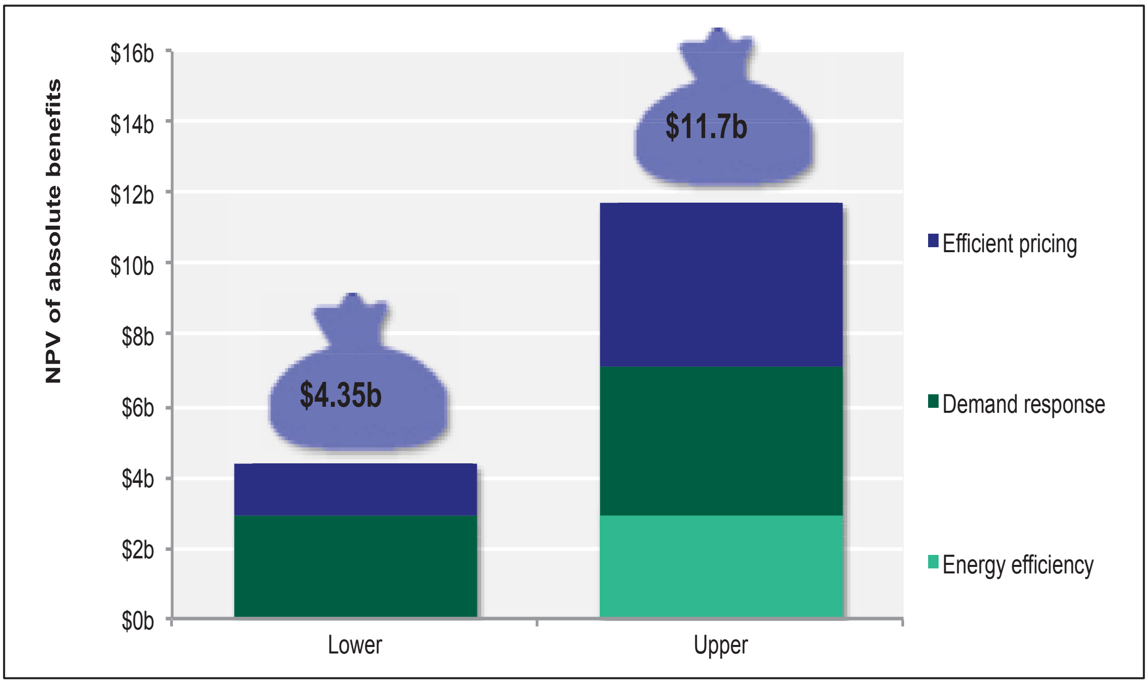

Figure 8-22 Potential benefits of demand management in the NEM (2013/14 - 2022/23) (AEMC 2012, p. 269)

Accordingly, the AEMC recommended that more cost reflective retail pricing be introduced,

> Rec. 14. There is a gradual phase in of efficient and flexible retail pricing options for residential and small business consumers through the introduction of cost reflective electricity distribution network pricing structures. The phase in of cost reflective network pricing would be through segmenting these consumers into three different consumption bands and applying flexible, (i.e. time varying) retail pricing options in different ways as outlined in the final report (AEMC, 2012, p. ii).

The proposed differing approach to these three consumption bands is illustrated in Figure 8-23.

However, as discussed in Section 6.6.2, such flexible time-of-use pricing is only possible where interval or smart meters have been installed. That most consumers do not have such meters is a major barrier to least cost outcomes.

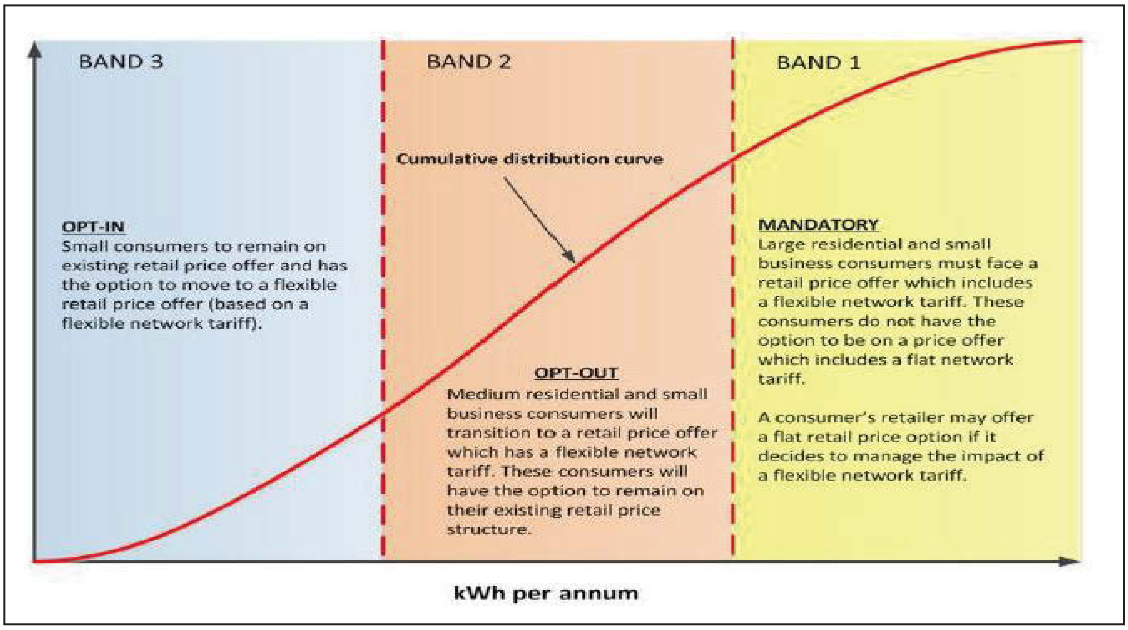

Figure 8-23 Applying flexible pricing to consumption thresholds

(AEMC 2012, p. 174)

Crucially, this is not just a technical issue. Even in Victoria, where electricity consumers do have universal smart meters, time-of-use pricing is generally not applied. This is in large degree due the mishandling of the rollout of smart meters and the poor public communication on the part the government and the utilities about the reasons for the rollout and the potential benefits to consumers (King 2015). High retail margins, aggressive and sometimes misleading marketing activities on the part of some retailers, complex and confusing retail offers, and the low level of effective competition in the retail market, have also eroded consumer trust in the electricity sector, making the introduction of flexible pricing much more difficult.

Recommendation R26: *Governments should work with retailers and consumer advocates to develop and implement flexible pricing offerings that are attractive and beneficial to consumers, accompanied by well-designed and delivered communication strategies.*

8.6.4 Retailer regulatory markets and energy efficiency obligations

There are other major objectives that impact on the retail market beyond those described by the criteria of the National Electricity Objective. For example, environmental objectives and social equity objectives are often applied to the retailers in the NEM. Examples of such additional objectives include the Renewable Energy Target, the energy efficiency obligation (EEO) schemes in Victoria, South Australia NSW and ACT and various community service obligations.

It is likely that the reliance on retail markets to meet goals beyond the national electricity objective will increase, particularly in relation to climate change. For example, from 2003 to 2012, the NSW Greenhouse Gas Abatement Scheme applied a carbon emission reduction goal to electricity retailers. The proposed National Energy Guarantee is currently expected to apply at the retail level in relation to both a reliability guarantee and an emissions guarantee (Energy Security Board, 2018).

Such mechanisms often include a bias towards centralised energy and against DE. Figure 8-24 illustrates this bias. Between April 2017 and April 2018, the price for large scale (centralised) renewable energy certificates (LGCs) ranged between about $76 and $87 per MWh. For small scale Renewable Certificates (STCs), the price has ranged between about $28 and $40 per MWh. By contrast, the price of energy efficiency certificates have remained much lower, between $10 and $27 per MWh. On this basis, it is evident that energy efficiency is a much lower cost resource.

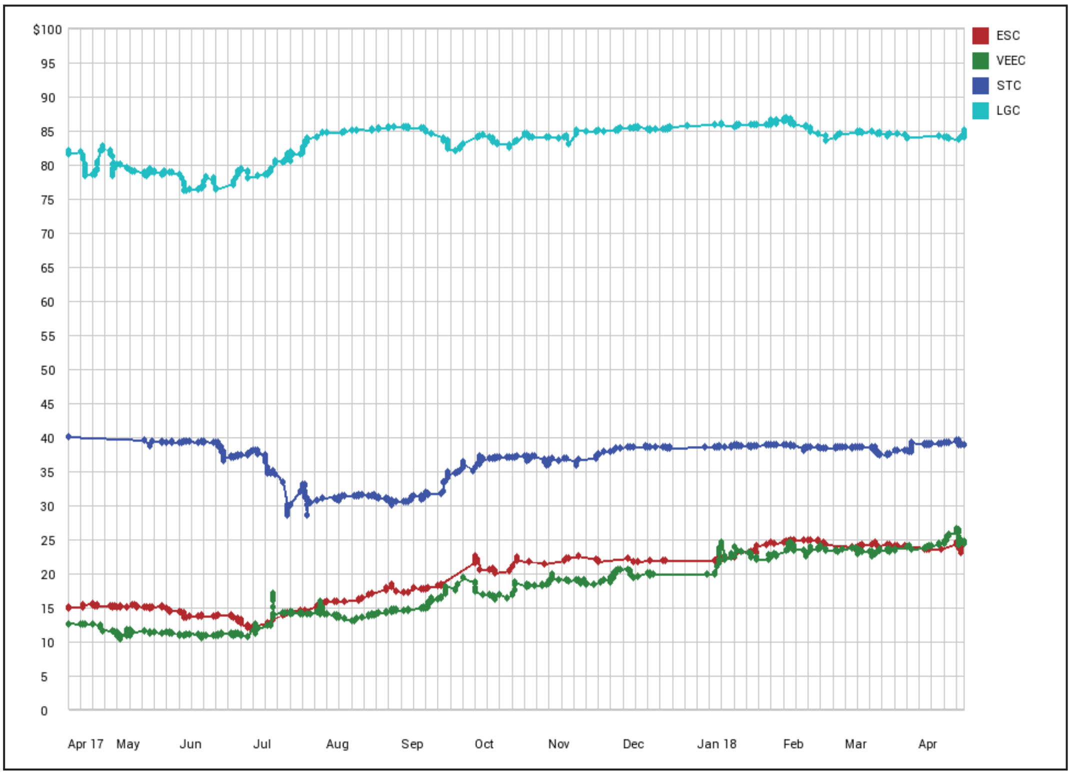

Figure 8-24 Certificate prices for energy efficiency, rooftop PV and large scale renewables (Demand Manager, 19 April 2018)

Yet even these figures significantly understate how much cheaper energy efficiency is compared to large scale renewable energy. In order to deliver large scale renewable energy to energy users, it is necessary to incur additional transmission and distribution network charges, which would typically amount at least an additional $100/MWh (or about $130/MWh for residential consumers, AEMC, 2017b). Energy efficiency, and in some cases, small scale renewable energy projects, such as those receiving STCs, avoid these network costs. It can be argued that certificate prices do not reflect the full cost of the resource. But even after allowing for this, energy efficiency (in the form of EEOs, like the NSW Energy Saving Scheme and the Victorian Energy Efficiency Target) currently provide, by far, the least cost means of providing megawatt hours to the electricity market.

The neglect of DE and energy efficiency in energy policy in Australia was recently highlighted in the high profile *Independent review into the future security of the national electricity market: blueprint for the future,* led by Australia's Chief Scientist Alan Finkel. This review included many constructive findings and recommendations, including in relating to emission reductions, DR and energy storage. However, it largely overlooked the potential for energy efficiency and EEOs for achieving emission reduction, reducing electricity bills and prices and supporting reliability.

This disregard of energy efficiency is exemplified by Figure 8-25, which shows the estimated current cost of a range costs centralised supply options. The intent of this graph was to show that renewable energy in the form of wind and solar generation are now cost competitive with fossil fuel based generation, even if the cost of "firming" is added to offset the variable output of wind and solar power.

However, what this graph, and the review in general, failed to do was to compare these centralised energy technologies with decentralised energy alternatives. Figure 8-26 corrects this oversight by adding the cost of for energy efficiency (in orange), which is presented conservatively here as *twice* the current price of energy efficiency in the Victorian and NSW EEO schemes. The comparison is enhanced by adding an indicative cost of network charges of $100 per MWh (and $50 per MWh for solar PV reflecting that it has the potential to be connected close to customer load an therefore avoids network charges).

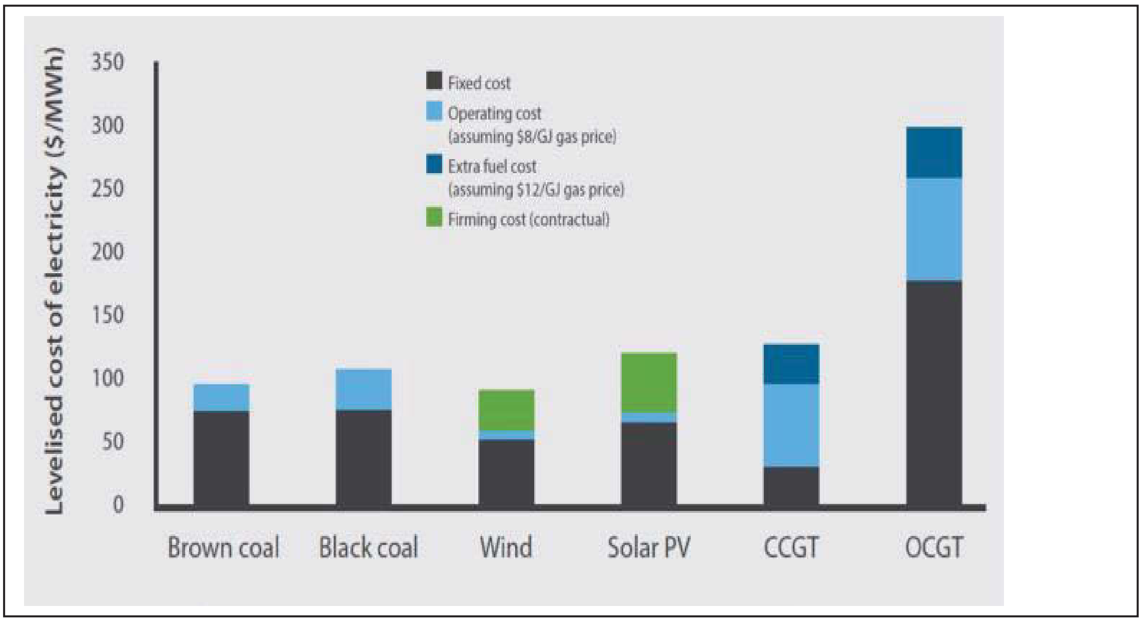

Figure 8-25 Levelised cost of electricity generation compared to cost of energy efficiency

(Finkel et al, 2017)

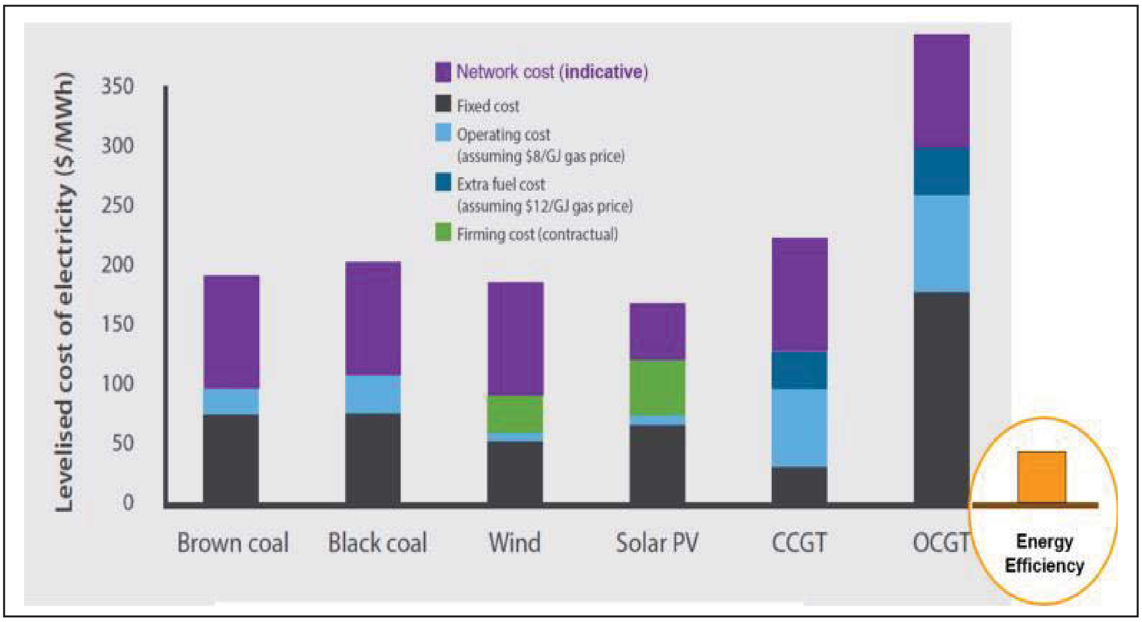

Figure 8-26 Levelised cost of electricity generation compared to cost of energy efficiency

(Dunstan et al, 2017, p.33, based on Finkel et al, 2017)

The consequence of this analysis is that if energy policy makers are committed to least cost outcomes for electricity consumers, then they should significantly expand the scale and scope of EEO schemes wherever they deliver energy efficiency for less than the cost of the alternative electricity supply option.

This principle is being increasingly recognised overseas. For example, the European Union has,

> a requirement that Member States establish energy efficiency obligation (EEO) schemes or alternative measures that would deliver a growing level of energy savings from measures delivered to end use energy customer … In the US, similar obligations are called energy efficiency resource standards (EERS's) and have been adopted in 26 states, even in the absence of a federal mandate. (Nadel et al. 2017).

As the retail market is currently being considered as the foundation of the NEG, then it is crucial that the NEG and associated policy are designed to access the lowest cost viable options, including decentralised energy and in particular energy efficiency and DM.

Recommendation R27: *Subject to public participation in policy making, the Commonwealth Government should establish a regulated cap and a market price on carbon emissions in the electricity sector. This could be via the proposed Emissions Guarantee of the National Energy Guarantee. Including such a price on carbon emissions will assist the market to deliver least cost competitive outcomes.*

Recommendation R28: *Policy makers should rapidly expand energy efficiency obligation schemes within the NEM wherever such schemes can deliver energy savings at less than the marginal cost of electricity supply and avoided network costs (or wherever the cost of the EEO scheme is less than the benefits of reduced pool prices).*

8.6.5 Least cost competition and electricity consumers

In concluding this chapter, it is important to return to the ultimate objective of least cost competition: to deliver least cost energy services to consumers, consistent with community preferences. While this depends in part on the efficiency of the electricity supply system, it also depends on what energy services consumers demand, and what choices they make in accessing them.

Consumer choice and participation

Much of the preceding discussion in this thesis relates to the supply side of the electricity market. However, as the overall objective is to deliver least cost energy services to consumers, it is just as important that efficient decisions be made about how energy is used. This includes decisions relating to behaviour, such as not wasting energy, but also decisions about the choice of appliances and the efficient design and operation of buildings and equipment.

In order for consumers to make efficient, well-informed decisions relating to these issues it is important that they have access to good information regarding the energy performance of the buildings and equipment that they use. It is also important that they have fair and equitable access to finance.

These issues have been discussed in Chapter 5 on the barriers to energy efficiency and demand management. To the extent that the identified barriers to consumers making good choices are identified, there are opportunities for electricity suppliers to assist in helping consumers to make such efficient decisions.

However, policymakers should seek to remove these barriers as a ‘first best’ solution so that utilities do not need provide a second-best solution. However, where removing the barriers is not practical, a second-best (DM) solution of a remedial policy response will often be preferable to the status quo.

Effective competition and consumer engagement

A key issue that has not been examined in detail in this thesis is the extent of market power and effective competition in the electricity market. As it derives from the principles of least cost planning, least cost competition is focused on how to achieve an appropriate balance of supply- and demand-side options at least cost. However, to deliver a least cost outcome within a competitive context, there also needs to be effective competition.

It is beyond the scope of this thesis to delve deeply on the issue of effective competition here. However, it is useful to highlighting the major aspects of effective competition.

The basis for effective competition is often presented within economic theory based on the concept of perfect competition. While perfect competition is a theoretical framework that is seldom approached in the real world, it does provide a useful basis for identifying the elements that are required for establishing effective competition. These conditions for perfect competition include:

- large numbers of sellers and buyers
- product homogeneity

- free entry and exit of firms
- profit maximization as the sole objective of firms
- no government regulation
- perfect mobility of factors of production
- perfect knowledge
- costless transactions

The further that a market is from meeting these conditions, the less likely it is to provide effective competition. None of the above conditions apply in the electricity system, with the possible exception of product homogeneity. At a more practical level, the lack of effective competition in electricity has been documented in numerous studies. For example, the *Independent Review into the Electricity & Gas Retail Markets in Australia* highlighted how unusually high retail operating costs and profit margins are both in Victoria and other parts of Australia compared to overseas jurisdictions (Thwaites et al., 2017. p. 17). It is therefore important that the principles of effective competition are also considered in practically applying least cost competition.

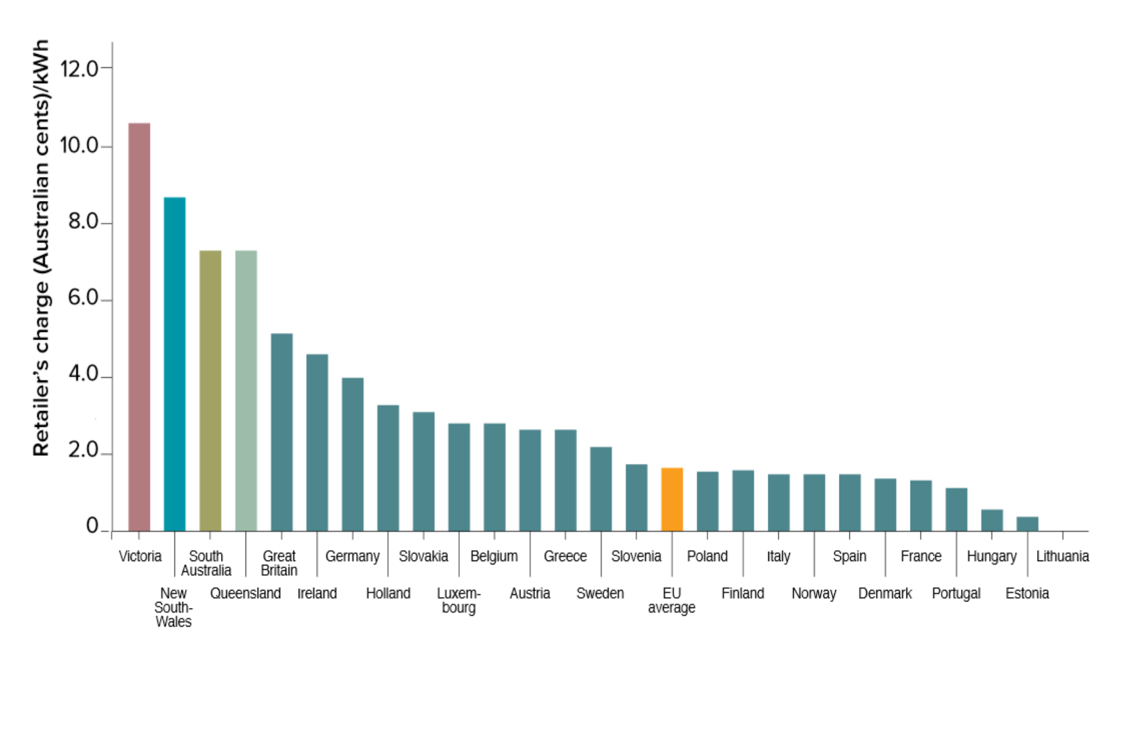

Figure 8-27 Comparisons of Residential electricity retailer charges

(Thwaites et al., 2017, p. 17)

This review found that:

> The poor consumer outcomes, including the high retail charge that Victorian energy consumers are paying compared with consumers in other Australian states, can be attributed to:
>
> - Increased retail costs driven by competition
> - The structure of the market
> - Industry practices that constrain competition and make customer engagement difficult. (Thwaites et al., 2017, p. 23)

Figure 8-28 shows the market share and market concentration (HHI) index in the retail market in NEM jurisdictions. As indicated, the big three gentailers account for about 70 per cent of the market in all jurisdictions, but the level of market concentration is falling, suggesting the extent of effective competition is rising.

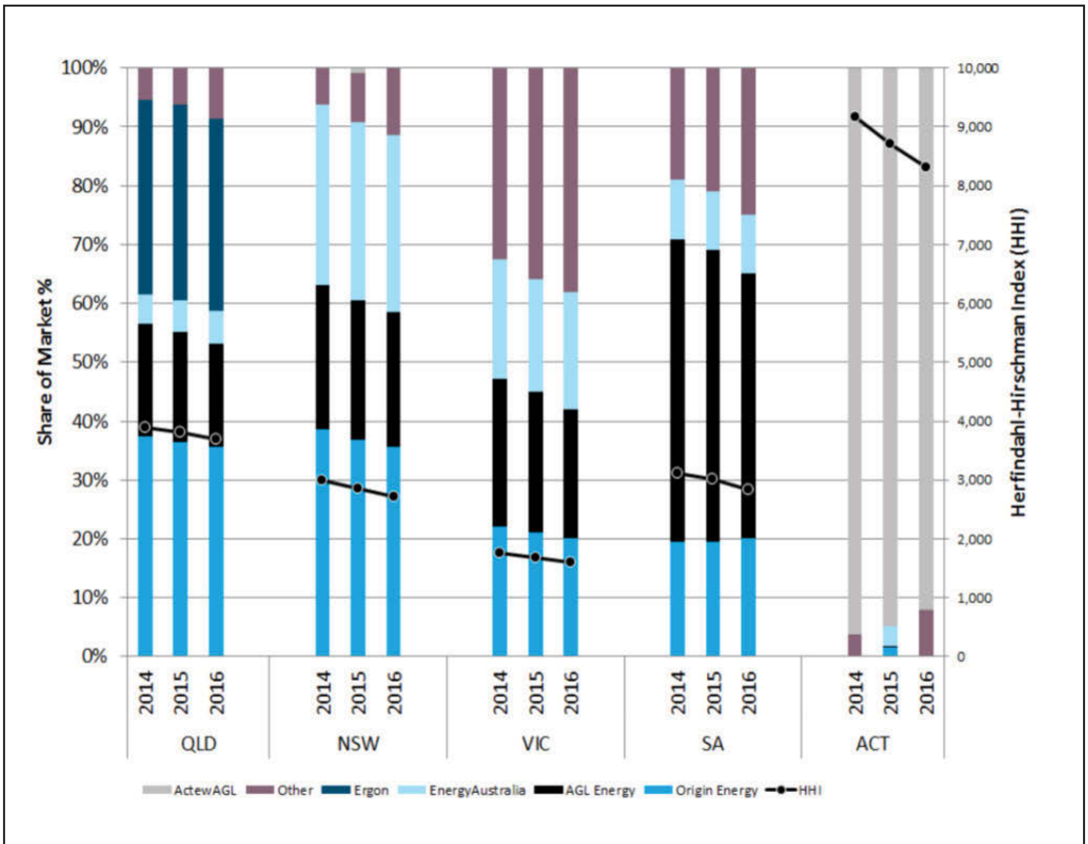

Figure 8-28 Retail electricity market share and market concentration in the NEM
(AEMC 2017c, p. 44)

This thesis has highlighted that competition itself creates costs and a liberalised market is not necessarily either competitive or efficient. In considering least cost competition, as for any other industry paradigm, it is crucial that the actual degree of customer service and satisfaction is monitored and that effective and efficient customer engagement is facilitated.

Recommendation R29: *Regulators and policy makers should assess the costs associated with both the operation of the competitive electricity market and the exercise of market power, and identify and adopt reforms to deliver effective, least cost competition.*

Chapter 9. Conclusions

'What do you get if you multiply six by nine?' – Douglas Adams

(The ultimate question of life, the universe and everything.
The answer being '42'; highlighting the importance of asking the right question.)

9.1 Summary of approach and outcomes

9.1.1 Thesis overview

As Section 1.5 provided a detailed written summary of this thesis, there is no need to repeat that summary here. Instead, I have reproduced the graphical summary of the structure and key innovative contributions of the thesis in Figure 9.1. Having reached this stage of the thesis, the reader should now have a much richer appreciation of what each element in this illustration represents and of the manifold relationships between them.

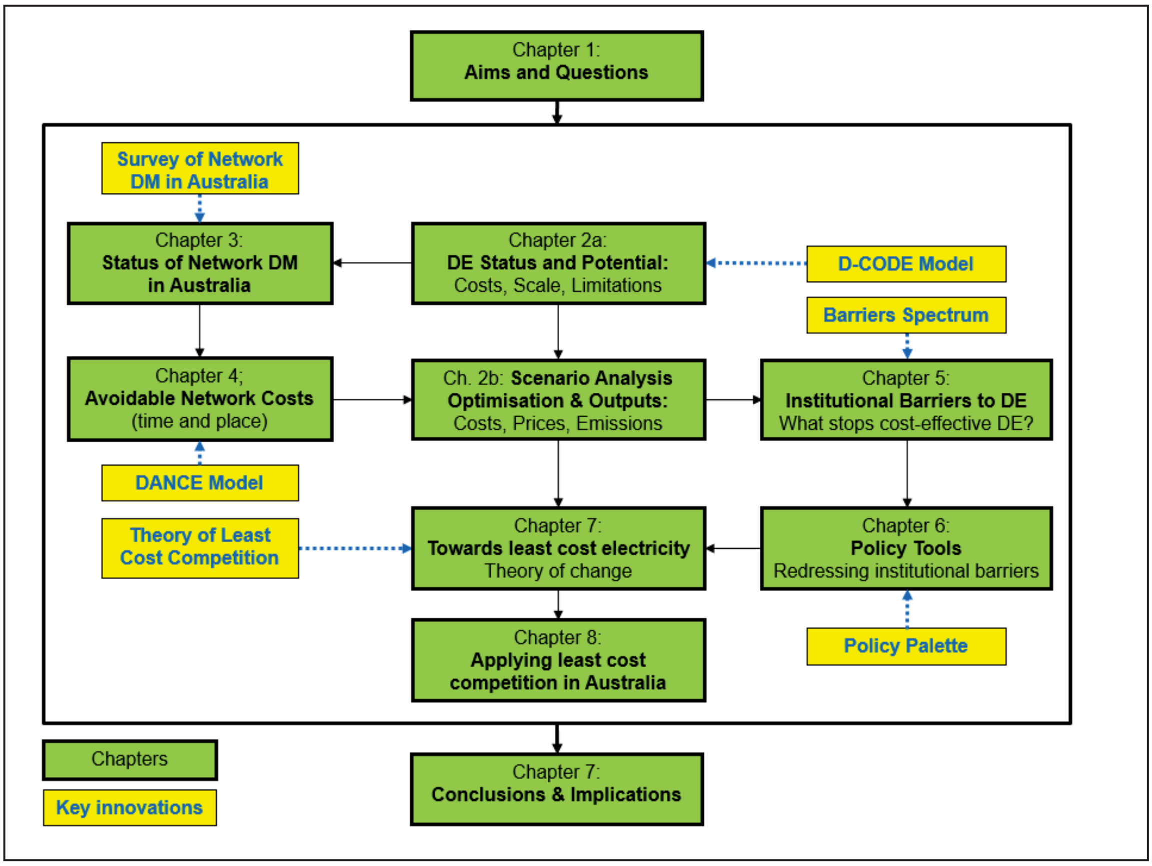

Figure 9-1 Structure and key innovative contributions of my thesis

It is also appropriate at the close of my thesis to reiterate my appreciation to my many research partners and collaborators as identified in my statement of acknowledgments. Without the generous support of all these people, this thesis would not have been possible.

9.1.2 Aims met and research questions answered?

At the outset of this thesis, I set out three overall aims and two research questions. In reaching the end of the thesis, it is time to reflect on my degree of success in meeting these aims and answering those questions.

Aim 1. To assess the potential to enhance economic efficiency and environmental sustainability by applying the principles of Least Cost Planning in the competitive electricity industry

This aim was complemented by the following closely related **research question:**

Research question 1. To what extent could greater use of demand management in the electricity sector lead to both lower costs and lower greenhouse gas emissions?

I approached this aim and the related research question in two ways.

My **first** approach was quantitative. In Chapters 2 and 3, the thesis assessed the status of DM and DE in the Australia National Electricity Market. This assessment is complemented with detailed modelling and analysis of what costs savings and emissions reduction could result from a significantly increased use of decentralised energy, as would be expected from applying DM in accordance with the principles of Least Cost Planning (LCP). Based on an innovative model, D-CODE, which I developed with the assistance of my colleagues for the purpose, and the best available data at the time, I estimated the potential value of savings from increased use of DE, at $2.9 billion per annum and emissions savings at 10.4 million tonnes of CO2e per annum, or 4.6 per cent of electricity sector emissions.

While the precise level of these actual benefits depends on numerous variables and the specific context, it is clear from my analysis that the scale of the expected cost savings over the next decade would be in the tens of billions of dollars and the emissions reductions in the tens of millions of tonnes of carbon dioxide.

Chapter 4 extended this quantitative analysis to the local level by developing a novel approach for calculating and mapping the value of network investment that may be avoided through the use of DM and decentralised energy. An important implication of this analysis is that past estimates of the potential cost and emissions savings from DM have generally been underestimates because they fail to assess the full value of avoided network infrastructure.

My **second** approach was qualitative. In Chapter 7, I considered how the principles of LCP could be applied to the competitive electricity industry. I found that neither traditional LCP nor the existing mechanisms of the 'competitive electricity market' would be successful in capturing the potential benefits of decentralised energy and DM highlighted in Chapters 2, 3 and 4. A different approach is required. Consequently, I sought to reformulate the essential principles of LCP in a form compatible with the competitive electricity industry. I have called these the principles of least cost competition.

Aim 2. To propose practical reforms to decision-making and resource allocation processes within the electricity sector to encourage more efficient use of demand management and decentralised energy resources.

In pursuit of this aim, I asked the following **research question**:

> *Research question 2. How could changes to the way that electricity networks are regulated, managed and developed lead to more efficient use of demand management?*

I approached this aim and the related research question in three complementary ways.

My **first** approach was analytical and consultative. The thesis identifies reforms to encouraging efficient use of DM and decentralised energy, through an extensive review of known and suggested institutional barriers to DM and decentralised energy in Chapter 5. I organised this list of barriers into an original taxonomy of these barriers, the Barriers Spectrum. I then empirically tested the validity of these suggested barriers in a survey of perceptions of relevant stakeholders.

This barriers spectrum provided a foundation for identifying policy tools to redress these institutional barriers. As for barriers, I organised these policy tools into my own original classification system, the 'PERFICT' Policy Palette in Chapter 6. These policy tools were tested and refined via a stakeholder consultation process and consolidated into a coherent policy reform agenda that was included in the Australian Decentralised Energy Roadmap (Dunstan et al, 2011f).

My **second** approach was theoretically focused. I recognised that simply proposing reform agenda is not sufficient to enact it. So in Chapter 7, I drew on theorists Kuhn and Kingdon to develop a theory of change for enacting the type of reforms described in Chapter 6. This theory of change recognises that electricity system institutions have developed over time reflecting a particular social-cultural context, or 'paradigm', and that reform depends on the confluence of a widely-acknowledged problem, a credible policy response and favourable politics. In Chapter 8, I applied this theory of change to the principles of least cost competition to suggest a credible policy response that may be appropriate in the political and economic paradigm prevailing in the Australian electricity system.

The **third** approach was practically focused, whereby I actively participated in the public policy debate in the Australian electricity system to disseminate the findings of my research. As discussed in Section 9.2 below, I enjoyed some success in that some of my proposed 'practical reforms to decision-making and resource allocation processes within the electricity sector' were adopted over the course of my research. However, it is still too early to tell how successful these reforms will be in 'encouraging more efficient use of demand management and decentralised energy resources'.

Aim 3. To do this with a particular focus on the Australian National Electricity Market.

My third aim was to focus my research inquiry on the Australia National Electricity Market. I maintained this focus throughout my thesis, but I also drew on overseas evidence where appropriate, and in particular from the United States, where the theory and practice of least cost planning arose. However, recognising that the challenges that the Australian electricity industry faces are widely shared overseas, I also sought to develop my research in a way that maximises its relevance to overseas jurisdictions.

If I were required to answer my research questions more concisely, I would respond as follows

> ***Research Question 1. To what extent could greater use of demand management in the electricity sector lead to both lower costs and lower greenhouse gas emissions?***

Answer: *Demand management has the potential to cut Australian electricity bills by billions of dollars per year while simultaneously cutting national greenhouse gas emissions by millions of tonnes per year. However, to tap these benefits requires cultural change and major reform of our electricity market. This reform requires prioritising consumers' and community interests and to make greater use decentralised energy through a process of least cost competition.*

Research Question 2. How could changes to the way that electricity networks are regulated, managed and developed lead to more efficient use of demand management?

Answer: *Electricity network businesses have the potential to be powerful agents for reducing electricity costs, cutting carbon emissions and improving supply reliability. To do this, network businesses' regulatory incentives must be better aligned with consumers' interests. This can be achieved by applying the five principles of least cost competition, namely: 1. Clear and appropriate objectives; 2. Public participation and accountability; 3. Cost-reflective pricing; 4. Competition among all viable options; and 5. Competition based on all relevant costs.*

9.1.3 Reflections on aims and research questions

In reflecting on my conclusions described above, I consider that I was reasonably successful in accomplishing my research aims. However, I have also come to a quite different perspective on these aims and research questions.

Firstly, I acknowledge that I have fulfilled slightly different aims and answered slightly different questions to those that I posed at the outset. For example, where my initial aim was focused on applying the principles of Least Cost *Planning* to the competitive electricity market, I have instead reformulated these principles of Least Cost Planning to become principles of Least Cost Competition instead.

Another example is where one of my initial research questions was focused on changing *network regulation and management* I found that, given the interactions between the different segments of the electricity market, it was necessary to engage more broadly with questions of electricity market reform. I have therefore presented a range of reforms not just for electricity networks, but for the generation and retail segments as well.

Secondly, I have come to appreciate that my research aims, as worthwhile as I still believe them to be, are less important than the purpose that lies behind them. This thesis was always intended to be based on evidence and sound argument. But it was also fundamentally more a quest for positive change than a positivist quest for truth. So while the conclusions of this research described above are important, I regard the impact of the research, described below, as more important.

9.2 Impact of my research

The research for this thesis took place over 13 years from 2005 to 2018. There were essentially three stages of this research. These were:

2005-2011: Phase 1 - Foundation and formulation

2011-2017: Phase 2 - Application and development

2017-2018: Phase 3 - Finalisation and outlook

Phase 1: Foundation and formulation (2005-2011)

The bulk of the research design and data collection took place in Phase 1. This was the period covered by the Intelligent Grid Research Program[56], as described in the acknowledgments. Key project elements of my thesis research in this phase included:

- Development and first application of the D-CODE model (see Chapter 2)
- Development and first application of the DANCE model (see Chapter 4)
- Development and stakeholder engagement with the Policy Palette (see Chapter 6)
- The Survey of Electricity Network Demand Management in Australia (see Chapter 3)
- The survey of stakeholder perception of barriers to DM (see Chapter 5)
- Development and publication of the Australian Decentralised Energy Roadmap (see Chapter 6).

[56] CSIRO Intelligent Grid Research Program, http://igrid.net.au/

These projects engaged a wide range of organisations and more than 700 individual stakeholders and included stakeholder consultation forums around Australia in Brisbane, Sydney, Melbourne, Adelaide and Perth.

This constituted a sizeable body of research and more than enough to complete this PhD. My original plan was to write up the outcomes of this research and leave my research there. However, while this research constituted a considerable contribution of new knowledge, it had also created significant momentum towards positive practical impacts on the electricity sector that I was keen to follow through.

The direction of this momentum for change was summarised in the Australian Decentralised Energy Roadmap (Dunstan et al., 2011) which set out a detailed program of policy reform as summarised in Figure 9-2. Many of the concepts and tools in this thesis have received strong support in impactful collaborative research projects as discussed below.

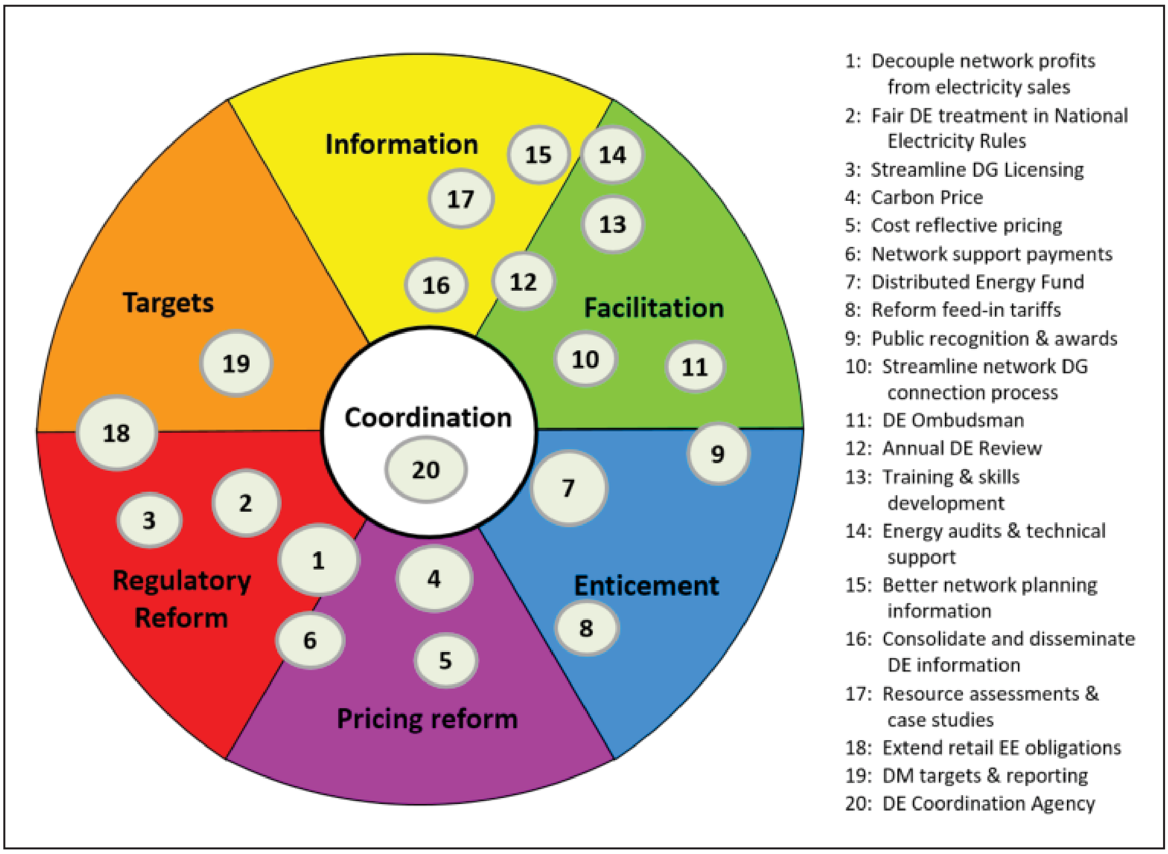

Figure 9-2 Priority policy tools from Australian Decentralised Energy Roadmap
(Dunstan et al, 2011, p.44)

Phase 2 - Application and development (2012-2017)

Phase 2 of my research focused on applying and further developing the tools and learnings of Phase 1 in order to fulfil the potential for positive impact. While this delayed the completion of my thesis, these efforts were also productive in supporting this positive impact. Figure 6-10 summarises the extent of this progress by colour coding each of the 20 policy tools according to my assessment of the degree of progress achieved since the publication of the Australian Decentralised Energy Roadmap in 2011. In my view, of the 20 policy tools presented, six can be regarded as having made moderate progress and a further four have made significant progress.

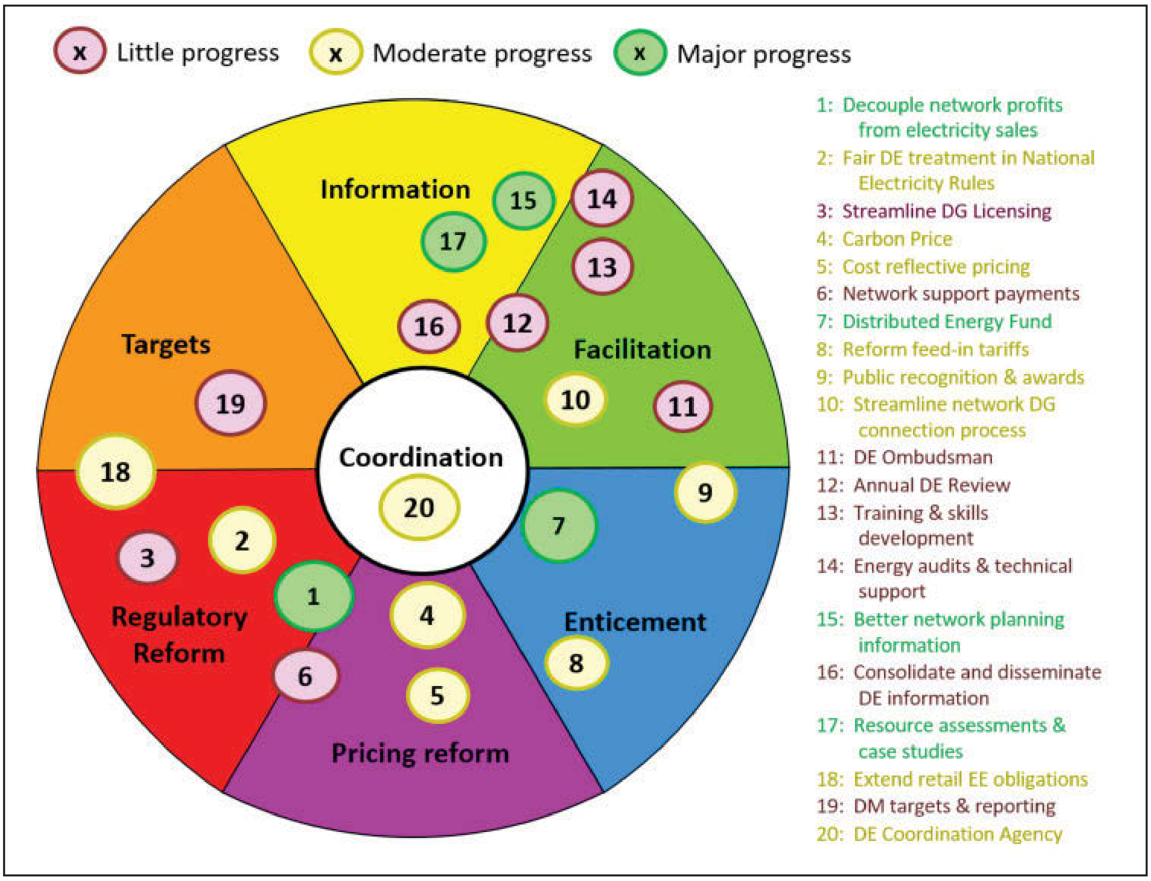

Figure 9-3 Policy tools progress since Australian Decentralised Energy Roadmap released (Dunstan et al, 2011, p.44)

Of course, I do not suggest that all of the progress achieved in the areas of Demand management and decentralised energy is attributable to my research and associated efforts. As Kingdon points out, major policy change never has a single cause or a single author. However, I am confident to lay claim that my research contributed to several elements of this progress, as described below.

Impact in areas of Major Progress:

Policy tool 1: Decouple network profits from electricity sales

The first major publication emerging from my thesis research was *Win, win, win: Regulating electricity distribution networks for reliability, consumers and the environment,* (Dunstan et al., 2008). This report emphasised the importance of decoupling network profits from electricity sales.

The report included the following recommendations.

> Recommendation 3: 'Decouple' Distributor profit from electricity sales…
>
> Recommendation 4: Use Revenue caps to decouple network profit from electricity sales…
>
> Recommendation 6: Use D-factor if revenue cap precluded (Dunstan et al., 2008, pp.8, 9).

This report and my associated advocacy was influential in the AER adopting a limited form of decoupling via the revised D-Factor in NSW in 2009 and, more importantly, in moving from price caps to a revenue cap in NSW, Victoria, and South Australia from 2014 (AER 2013, p. 43).

Policy tool 7: Distributed Energy Fund

My research conclusions have strongly supported the provision of specific financial incentives to support the rapid development of DE in Australia. As discussed in Section 6.7, such a policy tool can be very effective in overcoming the regulatory and other institutional barriers described in detail in Chapter 5.

My engagement in this policy space included two major research projects which involved extensive engagement with network businesses, the Australian Energy Market Commission (AEMC), the Australian Energy Regulator (AER), DE service providers and other stakeholders. These two projects were documented in the following reports:

- *Restoring power: cutting bills and carbon emissions with demand management* (Dunstan, C., et al, 2013)
- *Demand management incentives review: creating a level playing field for network DM in the National Electricity Market* (Dunstan, C., et al, 2017)

Starting in 2011, there followed six years of often intensive engagement, research and policy debate, including:

- the AEMC's Power of Choice review (AEMC, 2012), which concurred with my recommendation for a revised DM Incentive Scheme (Dunstan et al., 2013),
- endorsement of this proposal by the Standing Council on Energy and Resources Senior Committee of Officials (2013),
- a consequent change to the National Electricity Rules (AEMC, 2015), and
- a formal regulatory process by the AER which led to a revised DM Incentive Scheme being announced in December 2017 (AER, 2017c).

As noted in Section 8.5, the adoption of the revised DM Incentive Scheme makes available up to $1 billion in network funding to support cost effective network DM and decentralised energy over the forthcoming five-year network pricing determination period in the National Electricity Market .

Policy tool 15: Network Planning Information

Public provision of more accessible, comprehensive and clearer network data is a key focus of this thesis. The DANCE model (Chapter 4) was developed to support this goal. Since 2011, I have been heavily involved in improving this tool and approach through the three-year Network Opportunity Maps project which I have led at the Institute for Sustainable Futures.

This major project involved all 18 electricity network business in the NEM, policy makers, regulators and clean energy companies to develop free, annually updated, online maps of network constraints, planned investment and potentially avoidable costs across the Australian National Electricity Market. The maps provide clear, consistent and timely information on network opportunities and constraints for decentralised energy and DM project proponents.

The network opportunity maps help decentralised energy service providers to work with network business to anticipate future network constraints, reduce the need for new grid infrastructure and lower electricity bills. These maps should enable faster development of decentralised energy and DM by showing where and when such resources can be most cost effective.

The network opportunity maps project was finalised in October 2017 and responsibility for hosting and managing the maps was transferred to Energy Networks Australia.

Policy tool 17: Resource assessments and case studies

There has been a significant growth in resource assessments and case studies relating to DM and decentralised energy since 2011. The role of the Australian Renewable Energy Agency (ARENA) has been particularly influential in this regard. My research has also been a valuable contributor to this trend. In particular, in conjunction with my colleagues, I have been involved in the following influential resource assessments and case studies, including several of which applied the D-CODE model (Chapter 2) directly and/or key aspects of the D-CODE methods. These include the following studies:

- *Meeting NSW Electricity Needs in a Carbon Constrained World: Lowering Costs and Emissions with Distributed Energy,* (Rutovitz, J. and Dunstan C. 2009)
- *Demand Reduction Potential Review, 2012 to 2025, (*Dunstan, C., et al., 2012), Prepared for Ergon Energy Corporation Ltd, Queensland
- *Decentralised Energy Costs and Opportunities for Victoria*, (Langham, E., Dunstan, C., et al., 2011b),
- *Towards 100% Renewable Energy for Kangaroo Island*, (Dunstan, C., et al., 2016)
- *Beyond coal: alternatives to extending the life of Liddell Power Station,* (Dunstan, C., et al., 2017)

These studies have influenced government and regulators in setting energy policy and regulation and electricity utilities in major investment decisions.

The collective impact in the above four policy areas have potential to precipitate to a step change in the level of Demand Management in the NEM, particularly in network DM.

In relation to some of the policy tools in Figure 9-3 marked with moderate progress, my research also contributed impact, but to a lesser extent.

Phase 3- Finalisation and outlook (2017-2018)

Doctoral students are often advised that a PhD thesis is never finished, but, with luck and perseverance, it ends. And so it is in my case. There is still much to study and to learn and a much greater positive impact to be achieved. However, particularly with the Network Opportunity Maps formally adopted by the Australian electricity networks industry in October 2017, and with a much expanded and improved Demand Management Incentive Scheme adopted by the Australian Energy Regulator in December 2018, it was high time to bring my thesis to a conclusion.

The latter half of 2017 and early 2018 was a period of intensive synthesis and consolidation for my evidence and argument. In this period, I turned my focus towards questions about the potential usefulness of my thesis as a resource for progressing the development of decentralised energy and DM. Consequently, it was mainly at this time that I developed the conceptual framework of least cost competition as a means of simplifying the key messages of my thesis.

9.3 Further reform opportunities

As discussed in detail in Chapters 7 and 8, there have been numerous reforms recommended in relation to decentralised energy and demand management for the electricity sector in Australia over the last two decades, including by major reviews commissioned at the highest level of government. In many cases these recommendations have not been implemented. The challenge of effective change therefore clearly transcends simply recommending well-reasoned and evidenced policy reforms. On the other hand, successful reform has on occasion been achieved, as discussed in Section 9.2. The task is to glean from these successful examples the means to expedite remaining urgent and practical reforms.

Chapter 7 discussed key factors that need to be considered in successfully progressing reform. The principles of least cost competition were put forward as a means for doing this. Chapter 8 applied these principles to realising the full potential of decentralised energy and demand management in the Australian electricity sector. Chapter 8 also included specific policy recommendations to this end. In the spirit of a concluding chapter, I summarise these recommendations below. However, in doing so, I emphasise that these recommendations should not be mistaken for conclusions of this thesis (which are set out in Section 9.1).

The following summary of recommendations is presented not as a solution in its own right, but rather as a list of potential priorities to which the processes of reform, including the principles of least cost competition, may be applied. For convenience and clarity, these recommendations have been rearranged here to align with the principles of least cost competition.

Principle 1: Clear and appropriate purpose:

> **Recommendation S1:** As consumers are intended to be the primary beneficiaries of the National Electricity Market (NEM), changes to the objectives of the NEM should involve a fair and open process of public participation.

> **Recommendation S2:** Subject to Recommendation #S1, the NEM should adopt least cost to consumers, fairness and environmental sustainability as explicit objectives, in addition to the existing objectives of safety, quality, reliability and security.

Principle 2: Public participation and accountability

> **Recommendation S3:** The current public participation mechanisms should be strengthened and their scope broadened to include, for example, questions of the appropriate objectives for the National Electricity Market.

> **Recommendation S4:** The current public accountability mechanisms for the National Electricity Market should be improved to include clear and consistent reporting on performance against all objective criteria including least cost outcomes, safety, quality, reliability and security, fairness and environmental sustainability.

> **Recommendation S5:** The accountability for the NEM should include annual consideration and reporting of current and proposed reforms to better meet priority objectives identified via public participation.

> **Recommendation S6:** The accountability of the NEM should include annual consideration and reporting of current progress towards more cost-reflective pricing and proposed reform to expedite this progress.

Recommendation S7: The accountability of the NEM should include annual reporting of performance in fairly considering all potentially viable supply-side and demand-side options and should propose reforms to improve this performance where necessary.

Recommendation S8: The accountability of the NEM should include annual reporting of current performance in fairly considering all relevant costs and propose reform to improve this performance where necessary.

Recommendation G10: AEMO should continue to monitor and report on the performance of Demand Response in Frequency Control Ancillary Services and encourage the use of decentralised energy for other purposes in the NEM.

Recommendation N14: Governments and policy makers should support the Demand Management Incentive Scheme with education, facilitation and thorough annual reporting in order for the Scheme to fulfil its potential to level incentives between network capital expenditure and DM operation expenditure.

Recommendation N21: The Australian Energy Regulator should ensure consistent, consolidated annual reporting of network DM performance. This should include comprehensive reporting of impacts, outcomes, benefits and costs. This should include DM undertaken both within and outside the DMIS and price-based and non-price-based DM.

Recommendation N22: Commonwealth, state and territory governments should facilitate knowledge sharing on network DM activity between network businesses, DM providers, customer representatives and policy makers.

Principle 3: Cost-reflective pricing

Recommendation N15: Network business should adopt more cost-reflective electricity tariffs. This should include working with retailers and other third parties to provide innovative offerings combining smart meters, time-of-use tariffs and support for decentralised energy that can deliver lower bills for consumers and reduced net costs for network businesses, focusing on areas of network constraint. (This is particularly relevant in Victoria, where smart meters are already widespread. The DMIS could assist in this.)

Recommendation N16: Regulators, policy makers and customer advocates (such as Energy Consumers Australia) should assess and promote the potential for more cost-reflective pricing (and complementary decentralised energy) to deliver lower cost outcomes for consumers.

Recommendation N17: Commonwealth, state and territory governments should work with network businesses, retailers and customer and welfare representation to develop innovative flexible pricing and incentive options to give disadvantaged electricity customers access to the benefits of time-of-use tariffs, while protecting them from significant adverse impacts on bills.

Recommendation R26: Commonwealth, state and territory governments should work with retailers and consumer advocates to develop and implement flexible pricing offerings that are attractive and beneficial to consumers, accompanied by well-designed and delivered communication strategies.

Principle 4: Competition between all viable options

Recommendation G9: Commonwealth, state and territory governments should support a Demand Response Mechanism in the wholesale spot market. This will also encourage more DR in the contract market.

Recommendation R23: The AEMC should support allowing Demand Response to be bid into the spot electricity market from customers separately from the host retailer, as proposed by the Finkel Inquiry (2017), the AEMC (2012) and the Parer Inquiry (2002).

Recommendation G11: Commonwealth, state and territory governments should ensure that, if the Reliability Guarantee or an alternative mechanism is adopted to provide strategic reserve capacity for the NEM, then DM and decentralised energy should be allowed to compete fairly in providing this capacity.

Recommendation G12: Commonwealth, state and territory governments should ensure that decentralised energy technologies are fully considered and incorporated in developing renewable energy and carbon abatement policy instruments, such as the proposed emissions guarantee under the National Energy Guarantee.

Recommendation N13: Both short term and long terms incentives for the network businesses should be directed towards least cost outcomes for consumers. This includes:

- Short term: The form of regulation should maintain the recent reform to decouple network annual energy throughput from annual revenue and profit.
- Long term: The medium term regulatory determination should ensure that there is no incentive bias between capex and opex, or between network investment and DM options.

Recommendation N18: Distribution network businesses should take full advantage of the Demand Management Incentive Scheme (DMIS) in order to pursue cost-effective DM. This includes seeking to start the DMIS at the earliest opportunity, ramping it up to the fullest extent possible and encouraging industry-wide coordination.

Recommendation N19: The AER should actively support effective DMIS implementation. This support should include ensuring aggregated, standardised comparative reporting of distribution network business performance, including costs and benefits to consumers, highlighting best practice, and encouraging knowledge sharing.

Recommendation R24: Retailers should embrace the transition toward renewable energy and seek opportunities to use DM and decentralised energy to complement supply from variable output renewable energy.

Recommendation R25: Commonwealth, state and territory Governments and AEMO should research and promote the potential of DM and decentralised energy to provide firm capacity, and capacity firming services.

Recommendation R28: Policy makers should rapidly expand energy efficiency obligation schemes within the NEM wherever such schemes can deliver energy savings at less than the marginal cost of electricity supply and avoided network costs (or wherever the cost of the EEO scheme is less than the benefits of reduced pool prices).

Principle 5: Competition based on all relevant costs

Recommendation N20: The AER should make clear that it considers it prudent for a network business to undertake DM when the net cost of DM is less that the associated avoided cost to consumers of reduced expected unserved energy.

Recommendation R27: Subject to public participation in policy making, the Commonwealth Government should establish a regulated cap and a market price on carbon emissions in the electricity sector. This could be via the proposed Emissions Guarantee of the National Energy Guarantee. Including such a price on carbon emissions will assist the market to deliver least cost competitive outcomes.

Recommendation R29: Regulators and policy makers should assess the costs associated with both the operation of the competitive electricity market and the exercise of market power, and identify and adopt reforms to deliver effective, least cost competition.

9.4 Boundaries of this thesis and further research

As expansive as this thesis is, it raises many more questions than it answers. This thesis concludes that our society has much to gain from a large, rapid expansion of decentralised energy deployment and DM activity, and that the principles of least cost competition can facilitate this expansion. If these conclusions are sound, then it raises many relevant and interesting questions for further research. The following briefly outlines several of these.

- ***The history of DM and least cost planning in Australia***

  This thesis has provided a brief overview of the history of the development and application of demand management and least cost planning in Australia. These themes deserve a much more thorough treatment.

- ***Political ideology and electricity***

  One theme that has regularly emerged in this research is the role of political and economic ideology in driving the direction electricity policy in Australia and by implication elsewhere. An objective and evidenced based analysis of this topic is possible and could do much to illuminate the path to better outcomes for consumers and the community.

- ***Barriers to communicating the benefits of energy efficiency and DM***

  This thesis has identified very large potential benefits from increased energy efficiency and DM. It is far from the first study to do this. Yet these benefits are very poorly appreciated by policy makers and media. There would be great merit in better understanding why it is so hard to communicate the benefits of DM to policy makers and other stakeholders?

- ***Applying least cost competition***

  This thesis outlines a detailed theory of least cost competition. However, moving from theory to practice is not a trivial exercise. How could least cost competition be practically applied in different segments of the electricity system?

- ***Best practice for public participation in design and management of in competitive electricity markets.***

One of the five principles of least cost competition is public participation. As noted in this thesis, poor public participation in the development of the NEM has likely been a major contributor to the NEM's relative failure to date. But what would effective public participation have looked like? How can the will of consumers and the community be better reflected in the design and continual improvement of competitive electricity markets?

- ***DE and DM Reporting and Accountability***

The corollary of public participation is public accountability. How should we build performance reporting for DM and decentralised energy into the NEM's accountability systems, such as Energy Security Board's *The Health of the National Electricity Market* report and the AER's *State of Energy Market Report*? What other systems and mechanisms need to be established, such as, for example annual surveys of DM and decentralised energy?

- ***Accelerating the roll out of smart meters and dynamic time of use pricing and control***

Assessing the business case for accelerated voluntary rollout of smart interval meters, driven by consumer friendly time of use pricing and Demand Management.

- ***Develop an Efficient Pricing Index***

The "efficient pricing index" is proposed as a tool which can measure how cost reflective prices are in relation to costs. It would take the existing tariff structures and plot these against a trace of the effective cost of electricity supply over the same period to the extent to which prices correspond to the cost. Such a tool could be used in helping to identify opportunities for efficiency improvements.

- ***Tapping the value of avoided expected unserved energy as a value stream for DM***

Develop an analytical method and institutional/regulatory framework for applying Expected Unserved Energy or "energy at risk" to establish the business case for DM in network planning. For example, it would be helpful for the AER to clarify that it considers as network businesses undertaking DM where the net cost of DM is less that avoided cost to consumers of expected unserved energy.

- ***Mapping expected Unserved Energy in Network Opportunity Maps***

  As noted in section 8.5, there is a little understood bias against DM and DE in how the trigger point for providing new network capacity is determined in relation to valuing network reliability and expected unserved energy. This issue should be investigated. To support and extend this analysis, the network opportunity maps could be expanded to map forecast reliability levels and expected unserved energy.

- ***Comparative analysis of different forms of flexible capacity***

  How does DM, and in particular demand response, compare in cost, performance and environmental impact with other forms of flexible capacity, such as battery energy storage and pumped hydro-electricity storage (such as the proposed Snowy 2.0 project to expand the Snowy Mountains Hydro-electric Scheme).

- ***Modelling the NEM with high renewable energy penetration***

  It would be valuable to analyse and/or modelling what happens to the wholesale spot market and spot prices when most of the generation is essentially zero marginal cost and most of the time renewables are the marginal generator? What happens to the electricity contract market with frequent zero or negative spot prices? Would this cause the contract price to gravitate towards zero? Would we need then require a separate capacity market?

- ***Applying least cost competition to other sectors***

  How could the principles of least cost competition be applied beyond energy, in other domains with major centralised infrastructure and resource impacts, such as: gas, water, transport, and waste? Can least cost competition help support policy making in these areas, particularly in relation to integrating competition policy with other policy objectives.

* * *

9.5 Epilogue

9.5.1 Lost and prospective opportunities.

For decades, Australia’s electricity supply system has failed to protect the interests of the customers and community it is meant to serve. These failures include:

- In the 1970s and 1980s, the construction of excessive power stations by state owned electricity commissions.
- In the 1990s and 2000s, an excessive focus on privatisation, at the expense of public participation and broader community and consumer goals.
- In the 2000s and 2010s, excessive network investment and excessive returns on investment.
- Throughout this whole period, an excessive focus on the supply of electricity and a neglect of cost-effective Demand Management and decentralised energy.

In summary, whether state-owned or privately-owned, centrally planned or ‘competitive’, the evolution of the electricity system has maintained a common flaw – it was not focused on least cost competition. In other words, our electricity system has not been designed and managed to deliver lowest cost energy services to consumers, in accordance with the preferences of consumers’ themselves.

As in previous decades, we are grappling with new questions in the energy policy debate. These include:

- Should the Federal Government invest in large scale hydro-electric pumped storage, like the proposed $6-7 billion Snowy 2.0 project (Hutchens, 2017)?
- Should taxpayers money be used to build big batteries (Hair, 2018)?
- Should the Federal Government pressure private companies that own aging coal-fired power stations to extend their life (Farr, 2018)?
- What new policy mechanisms do we need to maintain reliability and security and cut carbon emissions (Australian Government, 2017)?

And, as in previous decades, we are overlooking the more fundamental and important questions:

- What do consumers want from their electricity system?

- What are the full range of options to meet these objectives?
- How do we encourage fair competition in the system to meet these objectives?
- How do we use smart pricing to encourage efficient use of energy and efficient investment decisions?
- What costs should be included in our decision-making?

Today, the details are different to the questions of the past, but the central theme remains. **How do we deliver an efficient electricity system that meets the needs of consumers and the community at the least cost?**

The good news is that, at least in Australia, the conditions for refocusing on least cost competition are better than ever. These conditions include:

- The shift to greater use of variable output renewable energy
- A policy bias that ostensibly favours competition
- A large fleet of coal fired power stations that are reaching the end of their economic lives.
- An emerging shortage of generation capacity.
- An unprecedented breadth and depth of understanding of the benefits of demand management and decentralised energy.
- An openness within the energy policy community to think beyond the conventions and institutions of the past.
- A group of relatively moderate and pragmatic governments in power across most jurisdictions of NEM.

Complementing these conditions, there have been several recent policy measures and proposals that lay the foundations for least cost competition reform. These include:

- The Demand Management Incentive Scheme, due to begin in 2018, which should encourage least cost distribution network development and, for the first time, allow DM and decentralised energy to compete fairly in providing network support.
- There are renewed proposals to allow DR to participation in the wholesale spot electricity market.
- The ancillary services market has been opened up to allow DR to participate.
- The Council of Australian Governments has committed to a target of increasing Australia's energy productivity by 40% by 2030.

From a ‘Kuhnian’ theoretical perspective, it could be asked: will the current crisis in the legitimacy of the NEM lead to a ‘normal’ (evolutionary) reform of the current competition paradigm, or will it lead to its replacement with a revolutionary new paradigm? And where does least cost competition fit in this?

These two questions highlight a potential flaw in the Kuhnian analysis. It may be more accurate to regard ‘normal’ and ‘revolutionary science’ as points on a continuum, rather than as essentially distinct processes. So, while it may be didactically useful to characterise particular scientific advances as clearly ‘revolutionary’ and others as clearly ‘normal’, there may be just as many that do not fit neatly into either category. In this context, to characterise a potential shift towards least cost competition as either evolutionary or revolutionary misses the point. The point is rather that, as Kuhn might describe it, a series of anomalies and challenges have arisen that demand a response, and least cost competition could provide a solution. Whether such a change is regarded as evolutionary or revolutionary is largely irrelevant. The solution to the problem is the relevant part.

9.5.2 And if not? Consequence of not adopting least cost electricity

As noted above, while least cost principles have been adopted overseas, Australia has never pursued least cost outcomes in the electricity sector. This has had severe impacts on consumers and the economy, but Australia remains a very prosperous society and economy. Does it really matter if Australia fails to adopt least cost principles?

There is a risk that the future costs of continuing the past unbalanced approach in the electricity sector in Australia may be even greater for two reasons. Firstly, the rising economic threat of low cost decentralised energy could plausibly “strand” billions of dollars of centralised generation and network infrastructure. This waste of potentially billions of dollars of value would need to be borne by either shareholders or taxpayers.

Secondly, and more importantly, the traditional centralised supply paradigm threatens to obstruct the emergence of clean decentralised energy and thereby delay the urgent decarbonisation of our economy. The economic costs of this delay could be enormous but the environmental and human costs could be much greater.

9.5.3 100% renewable energy is not enough

Worthy causes do not always deliver worthy outcomes.

In late 18th century France, revolutionaries pursued the laudable goals of 'Liberté, Egalité, Fraternité!', convinced of the righteousness of their cause. Within four years of the revolution, the Reign of Terror saw thousands executed as enemies of the Revolution.

About the same time in England, radical and reformist political philosophers like Adam Smith, Jeremy Bentham and later John Stuart Mill, pursued the goal of liberalising politics and the economy and transferring more decisions to the people via the 'free market'. The transformative power of their liberal economic vision led to the global trading structures that were established in the tandem with the expansion of British Empire - the greatest empire the world has ever seen. However, this unprecedented economic expansion came at the cost of massive disruption to communities subsumed into the Empire, including Raj India and Aboriginal Australia. Whether this is seen as a net positive or a net negative largely depends on which side of the various imperial conflicts one was on.

In the early 1990's in Australia, a 'neoliberal' reform agenda was adopted for the Australian electricity sector. This 'successful' example of microeconomic reform (AEMC/KPMG, 2013) has yet to deliver significant demonstrable benefits to consumers.

Likewise, today there is rising push for '100% renewable energy', which is embraced by its adherents with an enthusiasm and a self-belief no less than that of those who pushed for the other causes above. On the face of it, their goal, to eliminate carbon emissions from fossil fuels that are putting our global climate at risk, is undoubtedly a worthy one. However, like their predecessors, their success will likely depend on the extent to which they adopt prudent and balanced strategies in pursuit of their goal. The goal of 100% renewable energy can be achieved, but it will only be achieved smoothly, equitably and expeditiously, if it is pursued in accordance with the principles of least cost competition, or something very much like them. Otherwise, objections about cost, equity and social dislocation will delay or even derail the transition.

9.5.4 The era of least cost competition?

We can 'walk and chew gum at the same time'. We can keep in mind simultaneously the complementary ideas of competition, public participation and coordinated planning and we can weave them together harmoniously in our energy policy for the benefit of consumers and the sustainability of society. We can create a more balanced electricity sector.

A new era of least cost competition has most to offer consumers, but it also has much to offer electricity suppliers too. However, to make the most of these opportunities, the suppliers (that is, the generation owners, the network businesses and the retailers), need to adapt their outlook to this new age. If it is looked at from a 20th century perspective, the new era may seem threatening: the rise of variable output renewable leading to demise of baseload centralised coal and gas based generation; a more competitive environment; the rise of 'prosumers'; more complex planning and contracting; rapidly growing demand response and energy efficiency eroding the energy market volume, and so on. But from a 21st century perspective, each of these trends is a business opportunity for adding value to for customers and the community.

This change in paradigm towards least cost competition has already begun in our electricity businesses. How long it takes will also determine how fast we transition to clean, affordable, decentralised energy.

There has never been so much at stake in our energy decisions. Moreover, there has never been a better opportunity to embrace affordable, reliable and clean decentralised energy.

Our energy future hangs in the balance: to continue the errors of the past or to choose least cost competition.

The choice is clear. Will we resist change or jump at the opportunity?

'You must not fall.

When you lose your balance,

resist for a long time before turning yourself toward the earth.

Then jump.

You must not force yourself to stay steady. You must move forward.'

Philippe Petit

(To Reach the Clouds, 2002)

Philippe Petit, World Trade Center Walk
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