iGrid Project 4 -
Institutional Barriers, Economic Modelling and Stakeholder Engagement

Evaluating the Costs and Potential of Decentralised Energy
The D-CODE Model

Working Paper 4.3

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Evaluating the Costs and Potential of Decentralised Energy
The D-CODE Model
Working Paper 4.3, ver.2

Intelligent Grid Research Program
Project 4

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Institute for Sustainable Futures

Intelligent Grid Working Paper Series

Consultation and engagement with stakeholder are key elements of the Intelligent Grid Research Program. In order to encourage dialogue and collaborative learning, this series of working papers is being published during the course of the three-year program. These working papers will be revised and reissued from time to time as the research and consultation proceeds. Stakeholders are invited to comment on and contribute to the development of these working papers.

The working papers for Project 4 include:

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

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

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

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

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

The Australian Decentralised Energy Roadmap (published December 2011)

Submissions invited

This report is a working paper. We invite feedback and suggested improvements that we can consider in drafting subsequent versions of the document. In order to comment on this or other working papers, please email: louise.boronyak@uts.edu.au or refer to the Intelligent Grid website: www.igrid.net.au

D-CODE development and the iGrid Research Program

The Description and Costs of Decentralised Energy (D-CODE) model has been developed as part of the Intelligent Grid (iGrid) Research Program. This program is a three-year interdisciplinary collaborative research venture between the CSIRO and five leading Australian universities under the CSIRO Energy Transformed Flagship. Its aim is to demonstrate the economic, environmental and social impacts and benefits of the large-scale deployment of intelligent grid technologies in Australian electricity networks.

This paper on the D-CODE Model forms part of the work of Project 4, which focuses on institutional barriers, stakeholder engagement and economic modelling. For more details about the iGrid Research Program please refer to the iGrid website www.igrid.net.au.

Disclaimer

Acknowledgements

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1 Introduction

The interlinked challenges of climate change and energy affordability are prompting a shift from the traditional energy sector of centralised power generation and transmission networks. The vision for an ‘intelligent grid’ is emerging, where centralised generation is complemented by demand management, local generation and advanced network controls in order to minimise electricity costs and carbon emissions. Whilst there are few technical barriers obstructing such a transformation, significant institutional barriers still exist, as outlined in iGrid Working Paper 4.1. One prominent barrier is the lack of information available to compare the costs and benefits of different “decentralised energy” technologies and programs, 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 aims to fill this gap.

Unique to the 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 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 from a national scale to the local scale, assisting governments, utilities, local planners and other interested stakeholder groups in better understanding the true costs of generation options, and allowing informed decision-making towards a cost-effective, low carbon energy future.

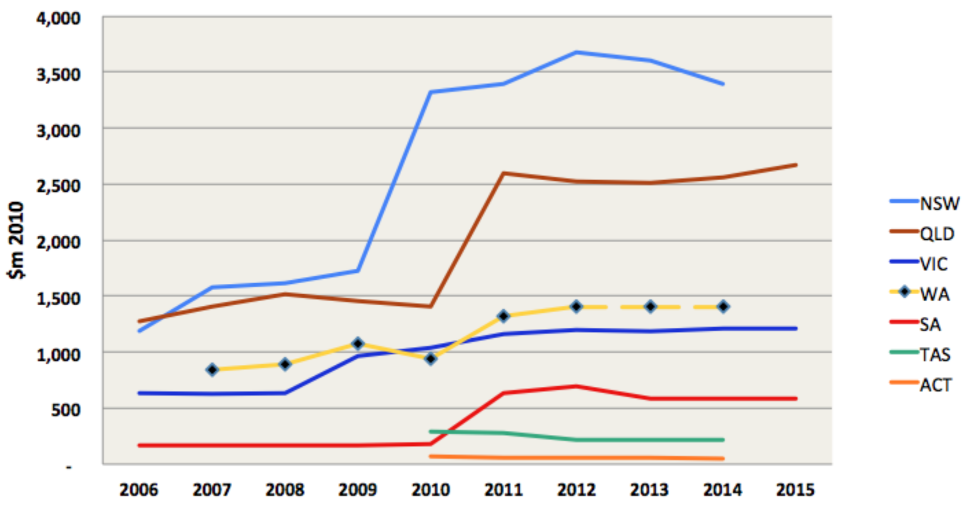
This paper begins by discussing the energy sector context behind the development of D-CODE in section 2, before outlining the purpose, the design principles and capability of the model in section 3. Section 4 outlines the D-CODE methodology, data requirements, and outputs, while section 5 discusses some general findings and implications of the model’s outputs at a national scale.

2 Background

2.1 Network augmentation costs

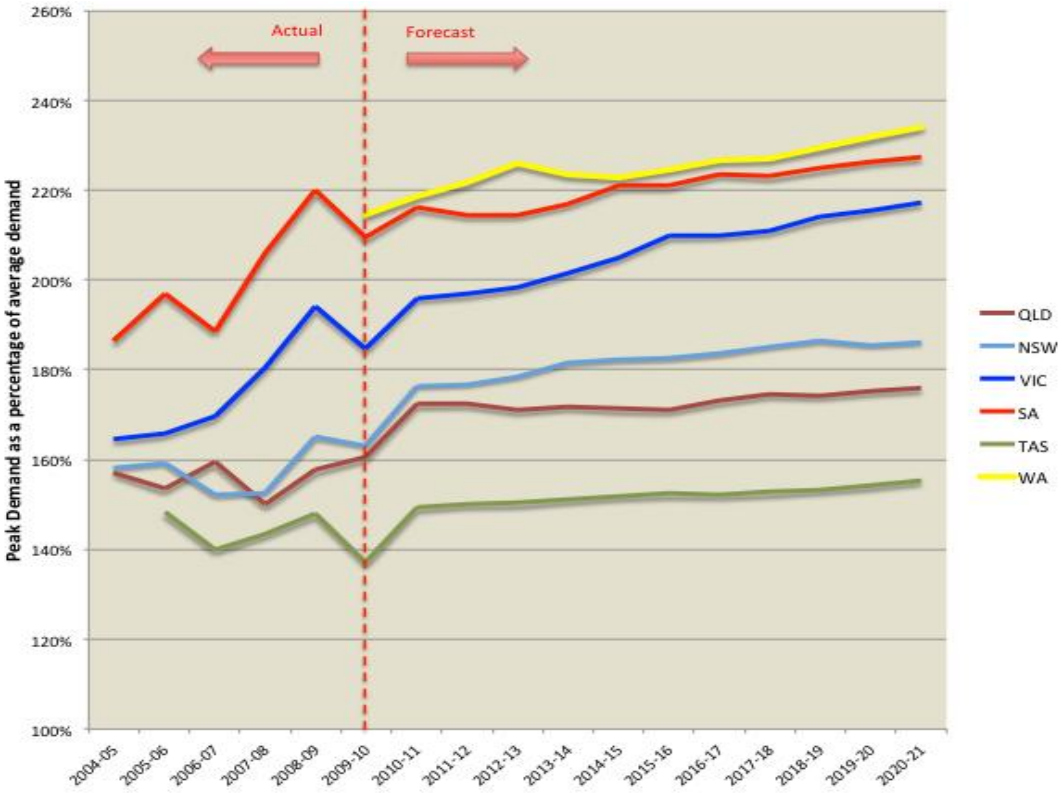
The Australian electricity market is currently seeing an unprecedented rise in infrastructure spending on electricity networks. Figure 1 below indicates the actual and forecast rise in network infrastructure spending between 2006 and 2015. Projected network capital expenditure investment between 2010 and 2015 totals more than $45 billion ($AUD2010) (iGrid Working Paper 4.4).

Figure 1- Electricity Network Capital Expenditure (T&D) by Jurisdiction, 2006-2015 (Source: iGrid Working Paper 4.4)



There are three main drivers for this network investment: ageing infrastructure replacement; increased reliability standards imposed by governments on electricity utilities; and growth in peak electricity demand. The final factor of rising peak demand is linked to a trend in Australia's energy usage whereby growth in peak demand is far outstripping growth in average demand. This trend of an increasingly "peaky" demand, shown in Figure 2 below, results in the need for more infrastructure to deliver each unit of electricity, thereby meaning higher costs for electricity delivered from centralised power stations to end users.

Figure 2: Actual and Forecast Peak Demand as a Proportion of Average Demand by State, 2004-05 to 2020-21



Data source: AEMO and WA Independent Market Operator 2010 Statement of Opportunities documents. Based on summer peak demand at 10% Probability of Exceedance (POE).

This additional investment has already resulted in substantial increases in real electricity tariffs in recent years, with further significant rises expected. Regulated retail tariffs in the Sydney region are forecast to rise by up to 83% between 2008/09 and 2013/14, around 70 percentage points coming from increased network charges (Dunstan and Langham 2010). It is estimated that $15 billion, or almost one-third of network expenditure, is to be invested to meet rising peak demand (Langham and Dunstan 2011). Given the capacity of decentralised or “decentralised energy” options to reduce demand on electricity networks, it is this pool of investment that is considered to be avoidable by ameliorating demand growth, such as through the implementation of decentralised energy. With community concerns over price increases already an issue, an opportunity exists to invest in decentralised energy in order to avoid further investment in network capital augmentation, and hence reduce upward pressure on future electricity prices.

2.2 The benefits of Decentralised Energy

Decentralised energy (DE) is defined as the installation of energy supply and demand management options close to where the energy is used, including local generation, end-use energy efficiency and peak load management (also called ‘demand side response’). DE reduces the need to augment the transmission and distribution system because the energy source is situated locally relative to where it is needed, as opposed to centralised generation. A study by Langham et al. (2010) found that 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 who 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. Of course, there are costs associated with the use of decentralised energy; these are quantified alongside centralised energy supply options in the D-CODE Model.

2.3 Rationale for the D-CODE model

As part of iGrid Project 4 research, a detailed literature review of relevant energy modelling tools was undertaken and can be found in Appendix 1 – Review of other models. This literature review identifies the different energy modelling approaches available at the time D-CODE was first conceived. Specifically it 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).

This review identifies that there is a dedicated 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, essentially understating the costs of centralised electricity generation relative to distributed generation (Electric Power Research Institute 2010; OECD 2010). D-CODE breaks new ground by incorporating network costs in the investment equation to allow a true cost comparison of the different centralised and decentralised energy options. Those models which have attempted to incorporate a more accurate reflection of DE costs and benefits are highly complex and sophisticated (e.g. Rocky Mountain Institute 2009; NREL 2009). In contrast, the strength of D-CODE is not in complex modelling power, but in its simplicity, transparency and accessibility.

3 Introducing the D-CODE model

3.1 Purpose

With Australian households and businesses concerned about rising electricity prices, 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 seeks to answer the key question: 'What are the lowest cost, low carbon way to ensure we meet our future electricity needs, using supply technologies and demand management opportunities available today?' Whilst this question is not unique as a modelling goal, D-CODE breaks new ground by incorporating network costs in the investment equation to allow a true cost comparison of the different energy options.[1] This removes the inherent bias against DE options present in a typical levelised cost analysis that does not consider the *delivered* cost of electricity.

3.2 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 energy 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 can be 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.

3.3 Functions

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

1. The generation of levelised cost curves to compare supply and demand side options side-by-side; and
2. 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.

3.3.1 Levelised cost curves

D-CODE generates levelised cost curves that provide a comparison of the costs and potential of different technologies to deliver electricity services. D-CODE integrates both demand and supply-

[1] The network costs are individually assigned to each technology based primarily on the how 'centralised' each technology option is – see 3.3.112 for more details on network cost methodology.

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 more to address shortfalls in peak power demand, the data is calculated and presented on two types of cost curves:

i. annual energy generation (in $/MWh, see Figure 3), and
ii. peak power generation (in $m/MWp, see Figure 4).

In both Figure 3 and Figure 4, the vertical axis represents the costs, which are broken down into components (represented by different colours) to provide insight into the cost composition of each technology. The horizontal axis represents the quantity of technology that could potentially be developed within the specific region and timeframe. Importantly, these graphs include network costs estimates assigned to each technology, and therefore avoid the inherent bias against DE that is present in typical levelised cost comparisons. DE options can be identified by the red label.

Figure 3 - Cost and potential of energy generation ($/MWh)

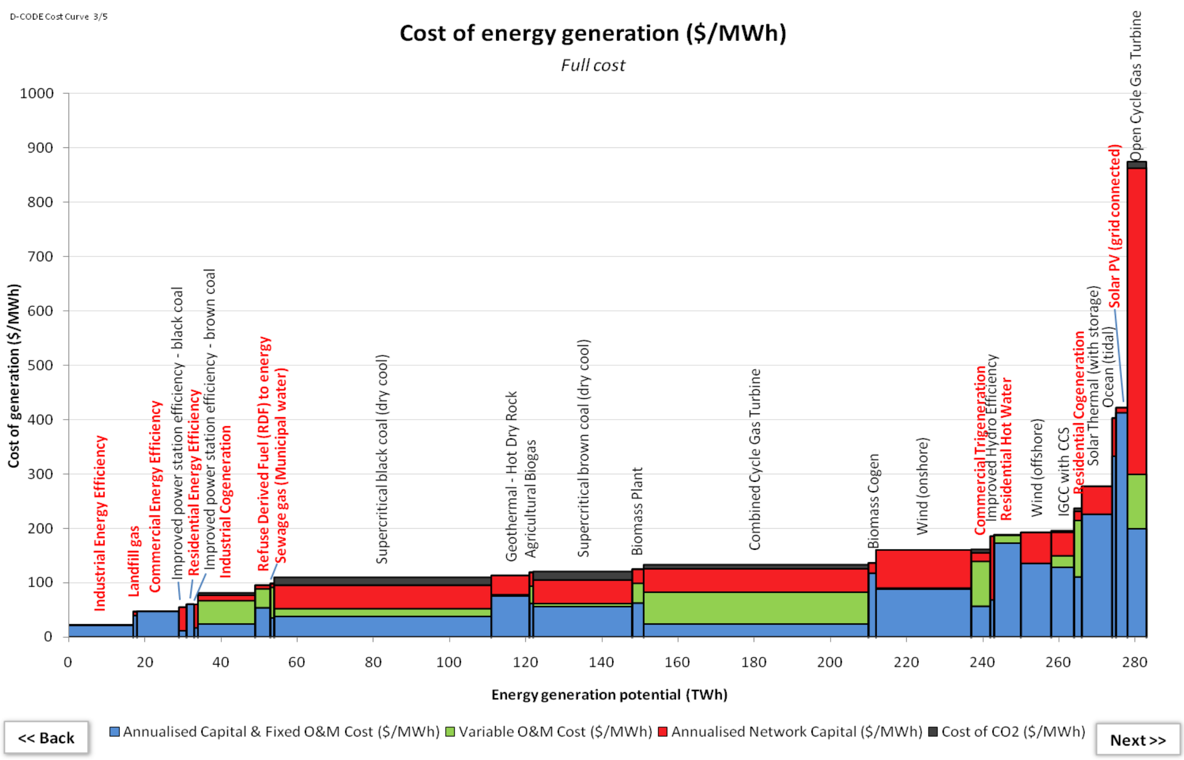
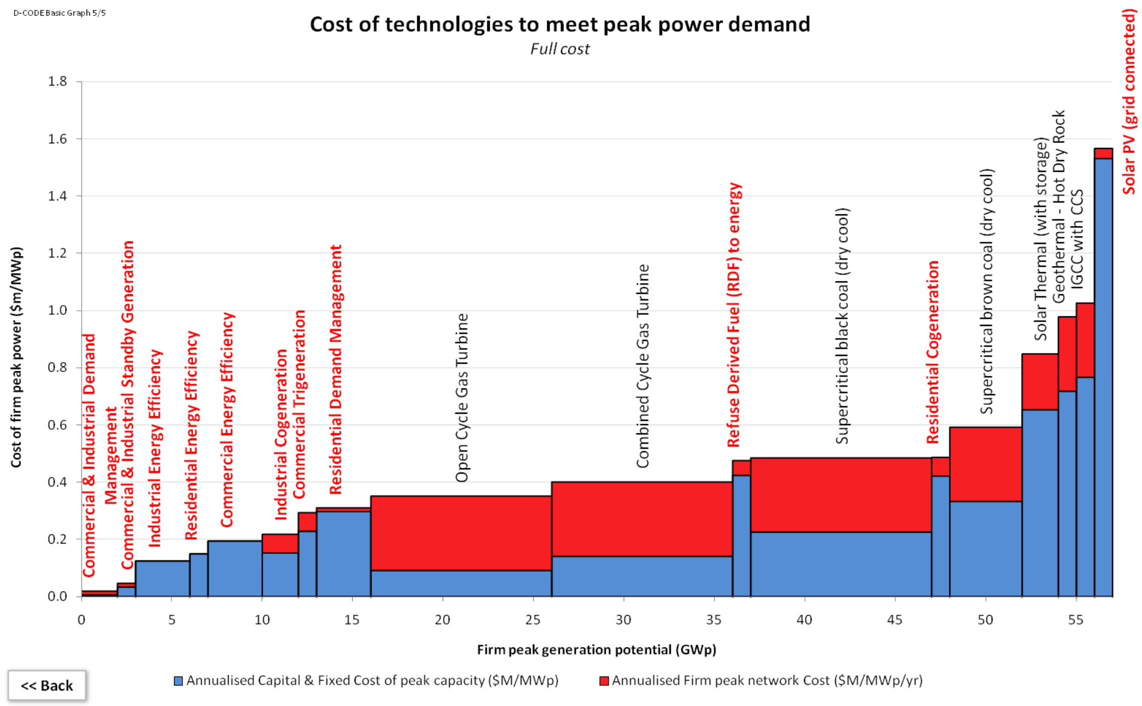


Figure 4 - Cost and potential of supplying peak power ($m/MWp)



Each cost curve serves a unique purpose. For example, if the electricity system in question requires additional energy supply, the energy cost curves (Figure 3) will provide an indication of the cost and quantity of installing additional energy available over the planning timeframe. If the electricity system in question is approaching a peak capacity constraint, the peak power generation curves (Figure 4) will provide an indication of the cost and quantity of installing addition capacity over the planning timeframe. However, often an electricity system may require both additional annual energy generation and peak power generation. The Optimum Mix Analysis is designed to select the lowest cost mix of technologies to satisfy these dual objectives (see Section 3.3.2).

Cost curve flexibility

The user can select 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 (whether 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 from the iGrid website along with the model itself.

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 determination methodology.

To view the source of the data, 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, calculation methodology, and referencing for each inbuilt technology and model assumption.

Network cost calculation methodology

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

The need for network capital expenditures will be dependent on the size of the capacity constraints, which often occur locally at the distribution substation 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 GIS to provide a dynamic picture of potential avoidable costs associated with decentralised energy for utilities and energy planners. D-CODE, on the other hand, looks at the energy system with a macro focus and therefore accounts for these typically local network investments by using an average annualized figure for an entire jurisdiction. This approach has been used previously by Langham et al. (2010) to account for the avoided network infrastructure costs from energy efficiency measures in a state-level analysis. Using updated figures from the work of Langham et al. (2010), the 'Default Network Capital Costs' shown in Table 1 below are used in D-CODE as the network cost associated with new centralised supply generation.

Table 1 – Network cost factors used in D-CODE (Source: Langham et al. 2010)

	National	NSW (incl. ACT)	Victoria	Queensland	South Australia	Tasmania	Western Australia	Northern Territory*
2010$m/MW	0.22	0.35	0.11	0.21	0.37	0.23	0.08	0.22

* NT was assigned the national average figure due to a lack of local data.

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 shown in Table 1 represent the average annual network cost 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). 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 network costs are 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 1. In other words, it 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 distributed technology such as commercial trigeneration is assigned a network cost factor of 25%, then the annualised network cost would be $0.22m x 25% = $0.055 million or around $55,000 per MW of peak generation capacity installed.[2]

As minimal research exists on the impact of installing individual technologies on network investment, ISF uses conservative estimations to assign network cost factors to individual technologies. For example, small scale solar photovoltaic cells, a highly decentralised form of electricity generation, has a network cost factor of 5% and is not assumed as zero because of network issues like voltage rise which are documented with widespread installation (Ergon Energy 2010).

3.3.2 Optimum Mix Analysis (OMA)

The second function of D-CODE is that it can model the lowest cost deployment of technologies and programs to meet the future energy needs of an electricity system. A hypothetical scenario, set-up by the model user, 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 – an optimal-mix case, and a business-as-usual (BAU) case. Screenshots of the OMA outputs are viewable in the case study below in Section 4.

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 and renewable/bioenergy 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)

[2]Note that these network costs are entirely independent of upfront capital costs to connect to the grid, which are typically assumed as capital costs.

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

Jurisdictional energy sector shortfalls are in-built from Australian Energy Market Operator demand forecasts (AEMO 2010).

Further detail on the OMA computations and how the user sets-up and runs the OMA is outlined in the D-CODE User Manual, downloadable from the iGrid website.

4 D-CODE Case Study: Australia 2020

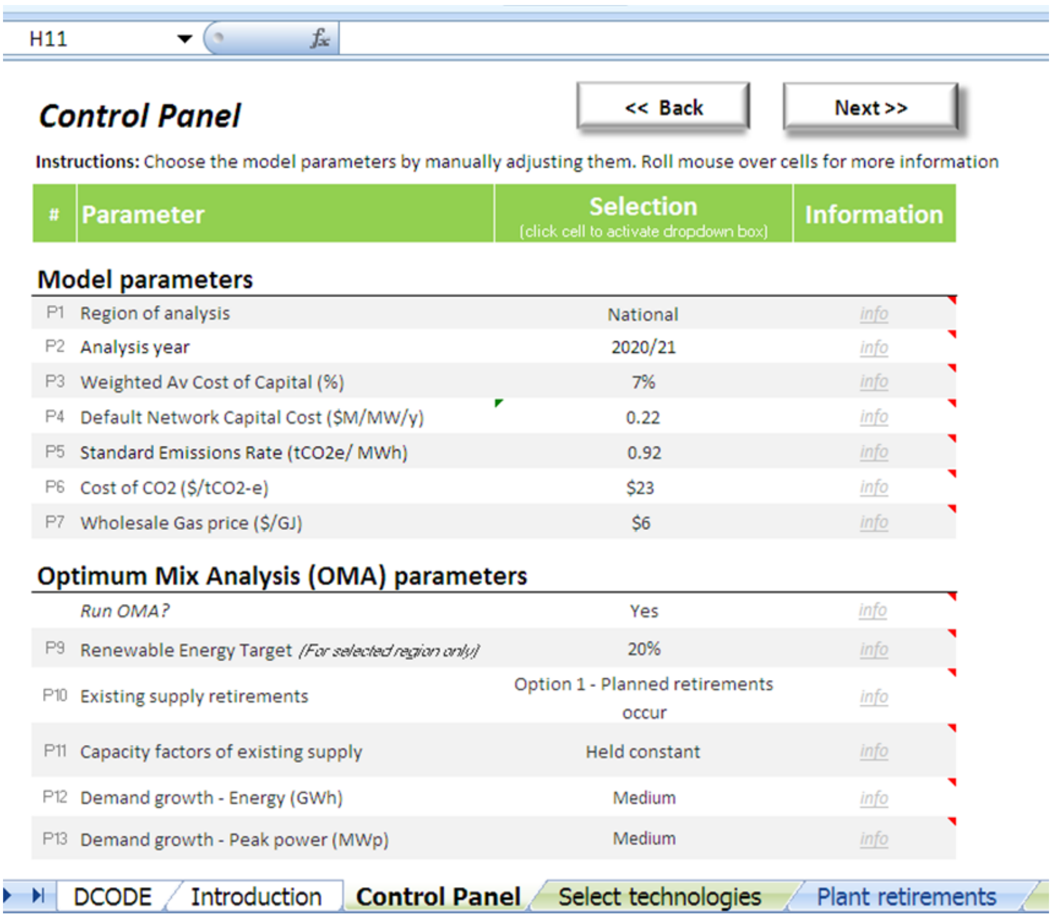
The D-CODE findings highlight the large cost disparity between DE options that avoid the need for network infrastructure, and the continued expansion of centralised generation capacity and network infrastructure. D-CODE presents these findings in a straightforward, powerful manner that clearly demonstrates that a shift away from a sole 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.

4.1 Inputs

To represent current market conditions, the ‘Control panel’ was set up as shown in Figure 5 below, with a $23 carbon price, network costs reflective of current investment, and a 20% Renewable Energy Target.

Figure 5 – Market parameters selected in case study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Control Panel

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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

4.2 Modelled energy sector constraints

Based on the selected market parameters, the following constraint levels are specified by D-CODE. In 2020, there is a 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 is required in 2020. Table 2 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 - Case study constraint levels and modelled values (annual values)

	Optimal mix	BAU
Constraint #1 applied: Peak capacity shortfall (new capacity req'd, 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	46,047	39,594
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)	26,759	30,600

4.3 Outputs

The numerical outputs are displayed in Table 3 below and graphical outputs are displayed in Figure 6 through toFigure 8.

Table 3 - Case Study Results: Optimal Mix vs Business as Usual (BAU) case

	Optimal	BAU	
Costs	**3.77**	**6.65**	**Annualised total cost ($billions 2010)**
	2.64	3.10	Annualised total capital costs
	0.41	0.48	Annualised total fuel and operation costs
	1.00	2.97	Annualised total network costs
	0.01	0.10	Annualised total carbon costs
	-0.14	0.00	Variable fuel O&M cost (avoided) from displacing existing generation
	-0.15	0.00	Carbon cost (avoided) from displacing existing generation
Peak demand/supply			***Peak demand MWp, analysis year***
	61,925	61,925	BAU peak demand MWp
	-6,352	0	Peak demand reduction from BAU MWp
	55,574	*61,925*	*Total system peak demand MWp*
	-10.3%	0.0%	Percentage reduction in peak demand from BAU
			Peak supply MWp, Analysis year
	52,434	52,434	2011 peak capacity of existing generators, MWp
	552	552	Change in peak capacity, between 2011 and analysis year, MWp
	52,986	52,986	Total peak capacity of existing generators, analysis year MWp
	2,587	8,939	Modelled additional peak capacity, MWp
	55,574	*61,925*	*Total system peak supply, Mwp*
	4.9%	16.9%	Percentage increase in peak supply, MWp
Annual Energy demand/supply			**Annual Energy demand GWh**
	279,700	279,700	BAU 2020 energy demand GWh
	-19,204	0	Energy demand reduction GWh
	260,496	*279,700*	*Total system energy demand GWh*
	-6.9%	0.0%	Percentage reduction in energy demand from BAU
			Annual energy supply GWh
	237,822	237,822	2011 generation of existing generators, GWh
	2,285	2,285	Change in generation potential, between 2011 and analysis year, GWh
	240,106	240,106	Total potential provided by existing capacity, analysis year, GWh
	233,737	240,106	Total required supply from existing generators, analysis year, GWh
	26,759	39,594	Modelled supply side generation, GWh
	260,496	*279,700*	*Total annual energy supply GWh*
Emissions	0.40	4.32	Emissions of added generation MtCO2
	215.90	222.37	Emissions of existing generation MtCO2
	216.29	226.69	Total emissions, MtCO2
	0.83	0.81	Standard emissions rate, kgCO2/KWh
	-4.6%	0.0%	Compared to BAU, analysis year
	4.6%	9.6%	Compared to 2010 (forecast) emissions
	67.1%	75.1%	Compared to 1990 emissions

Figure 6 – Case study output, Deployed technologies to meet energy and peak capacity shortfalls in BAU case

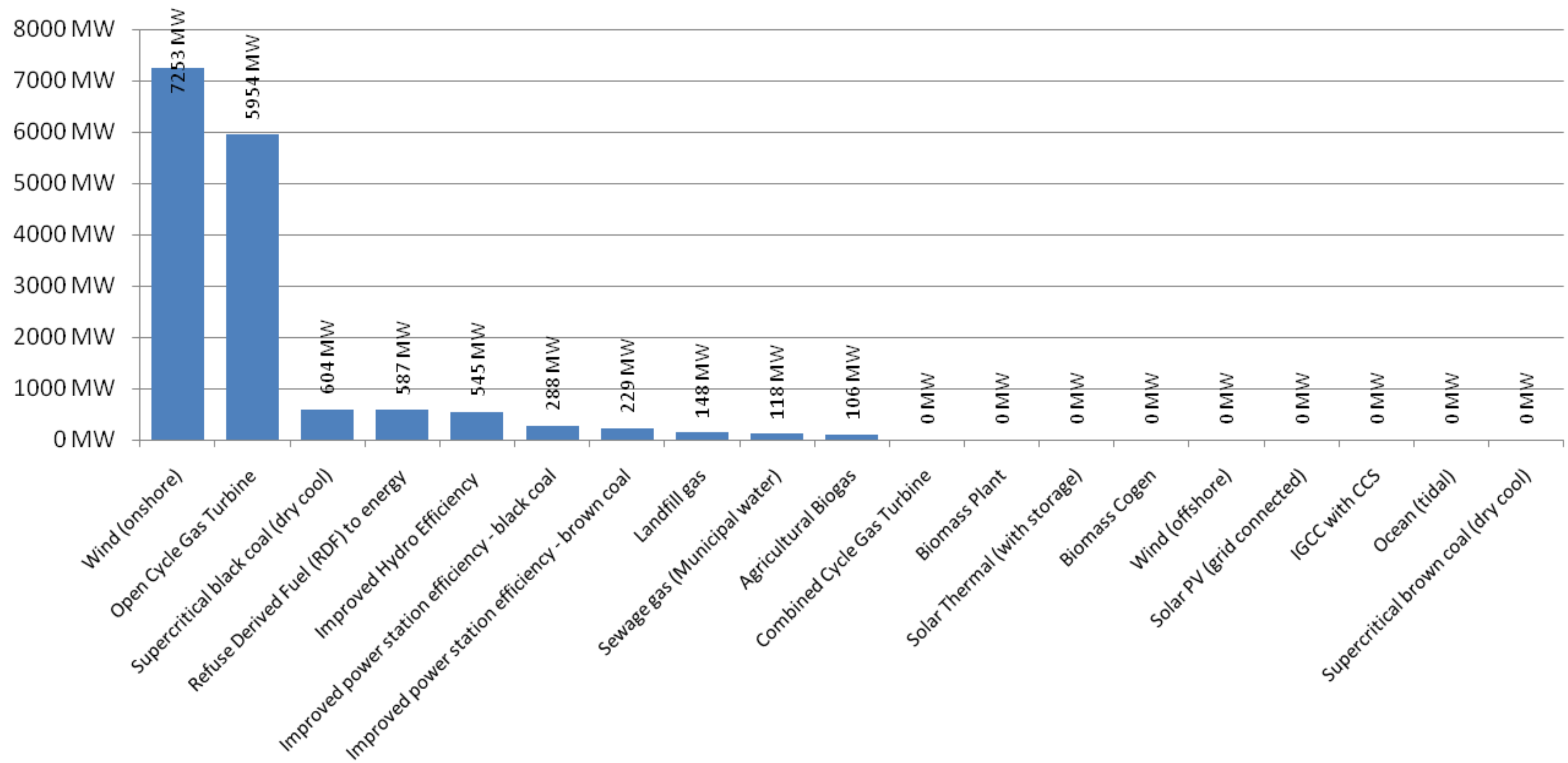


Figure 7 – Case Study output, Deployed technologies to meet energy and peak capacity shortfalls in Optimal Mix case

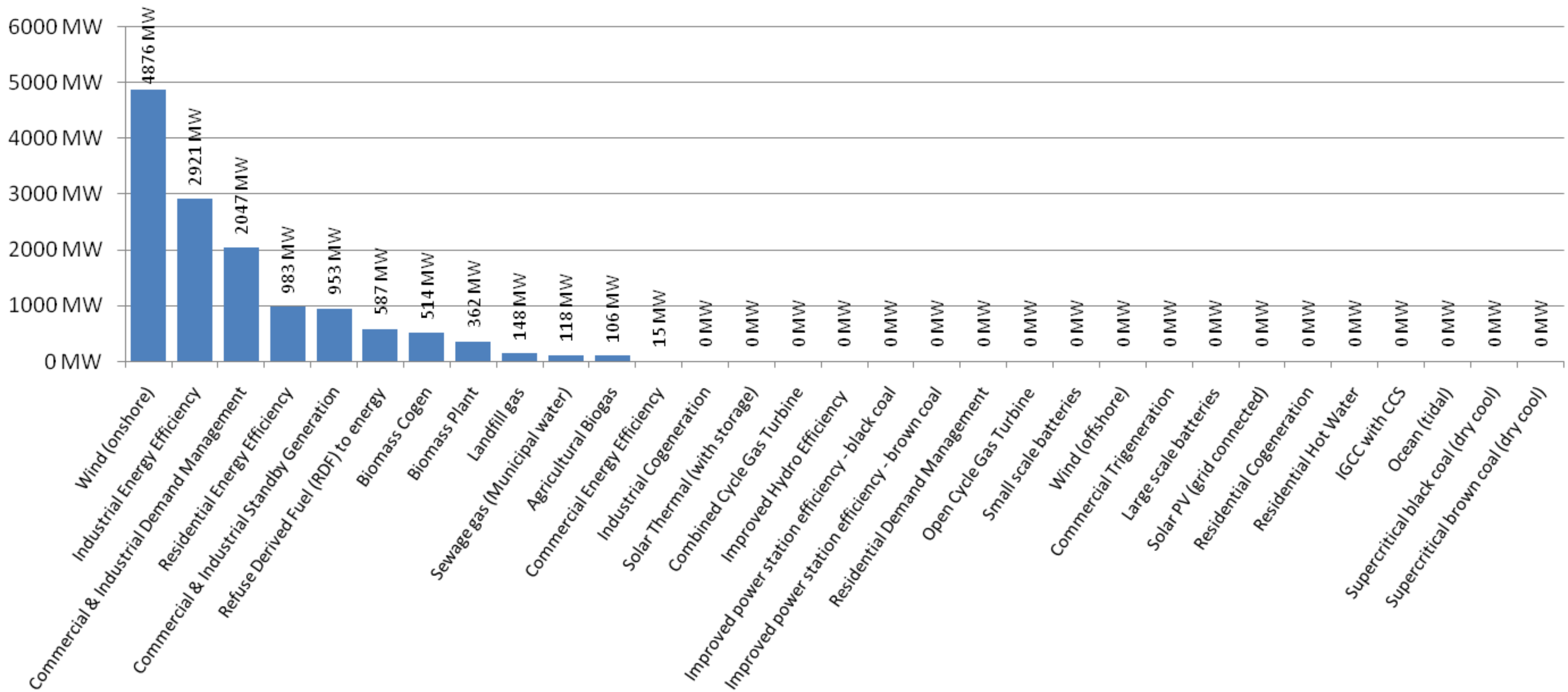


Figure 8 – Case study output, Modelled new peak capacity to meet 2020-21 shortfall in BAU case by category (L) and technology (R)

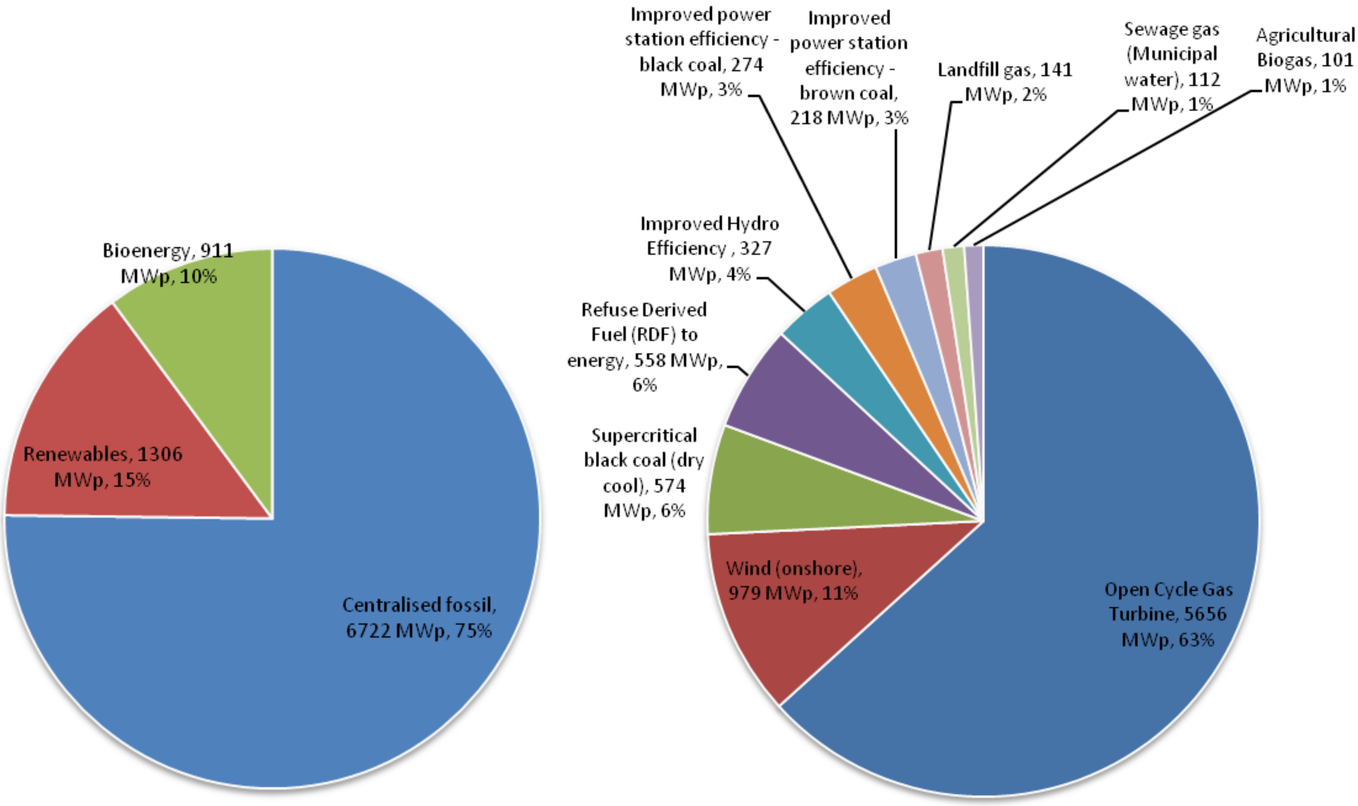


Figure 9 – Case study output, Modelled energy generation to meet 2020-21 shortfall in BAU case by category (L) and technology (R)

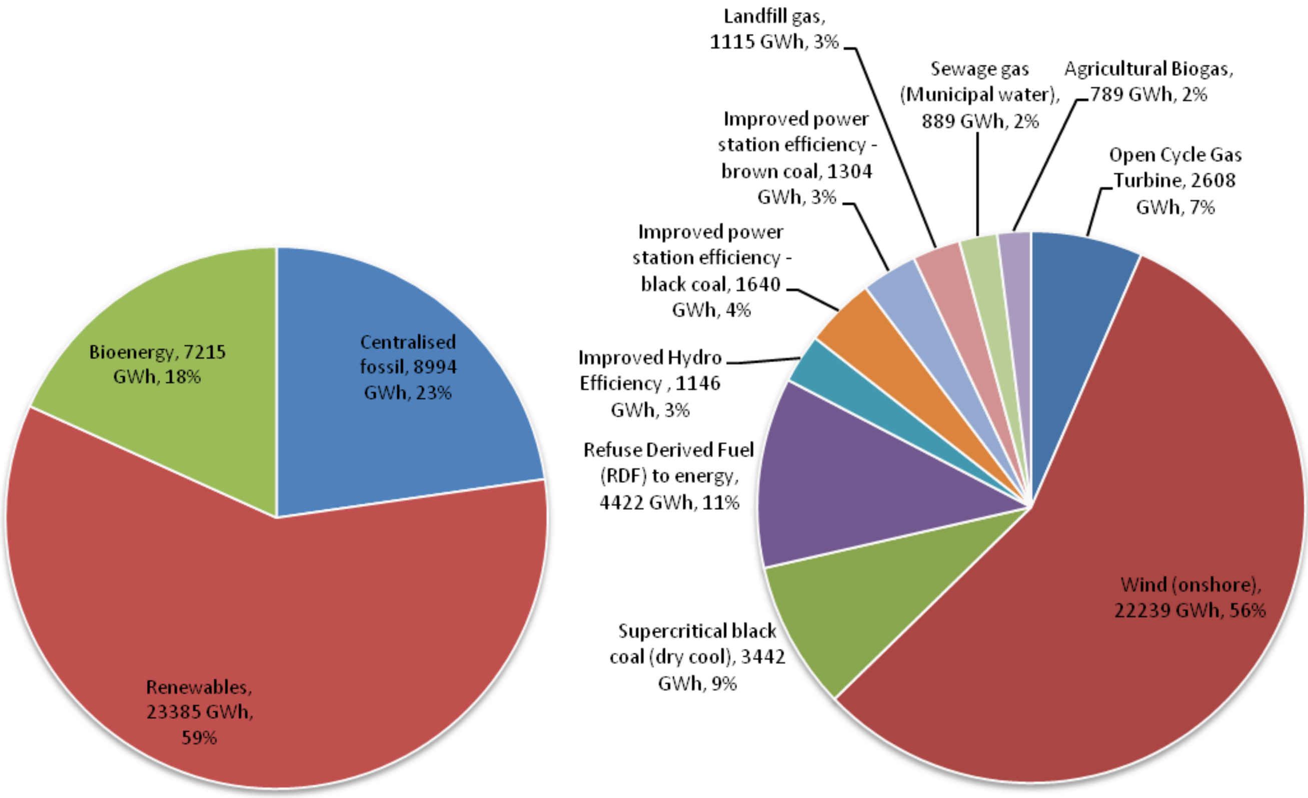


Figure 10 – Case study output, Modelled new peak capacity to meet 2020-21 shortfall in Optimal Mix case by category (L) and technology (R)

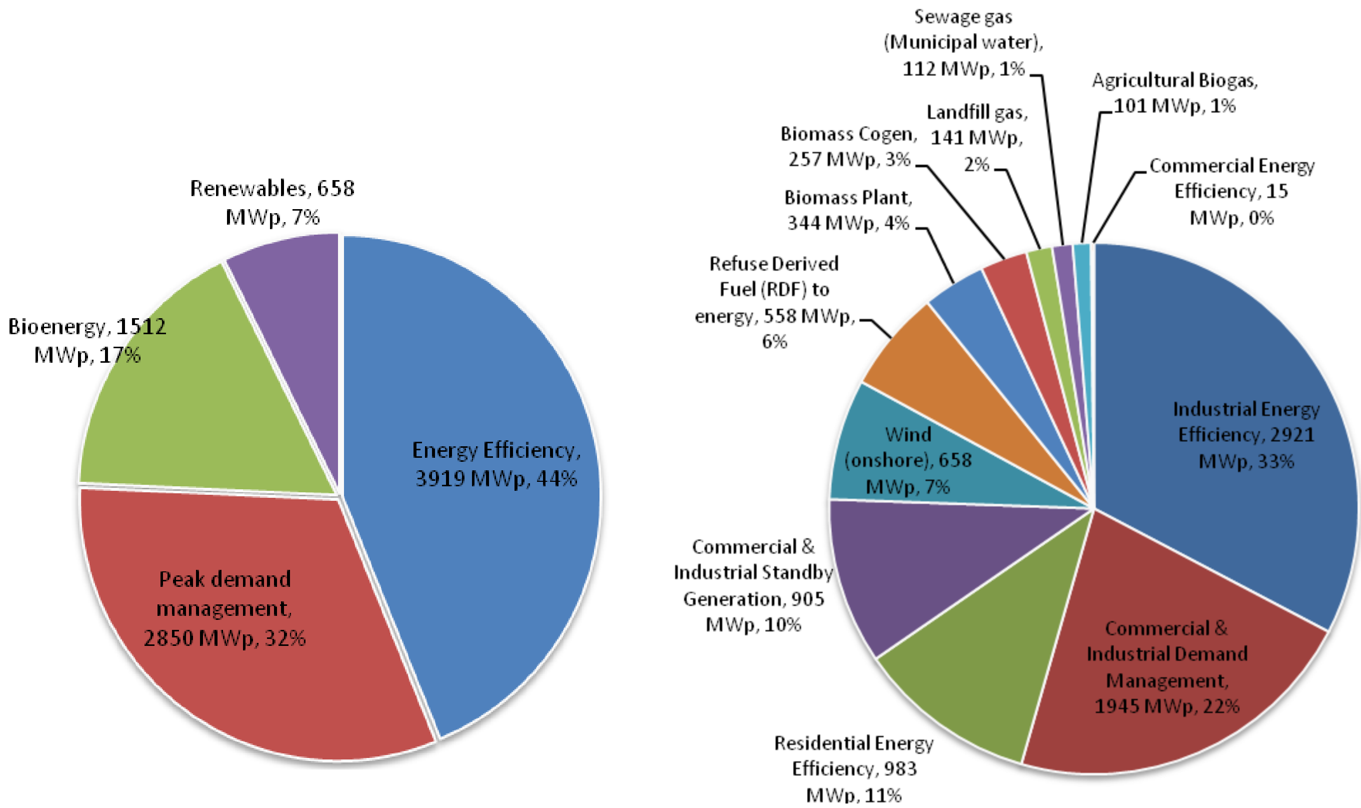
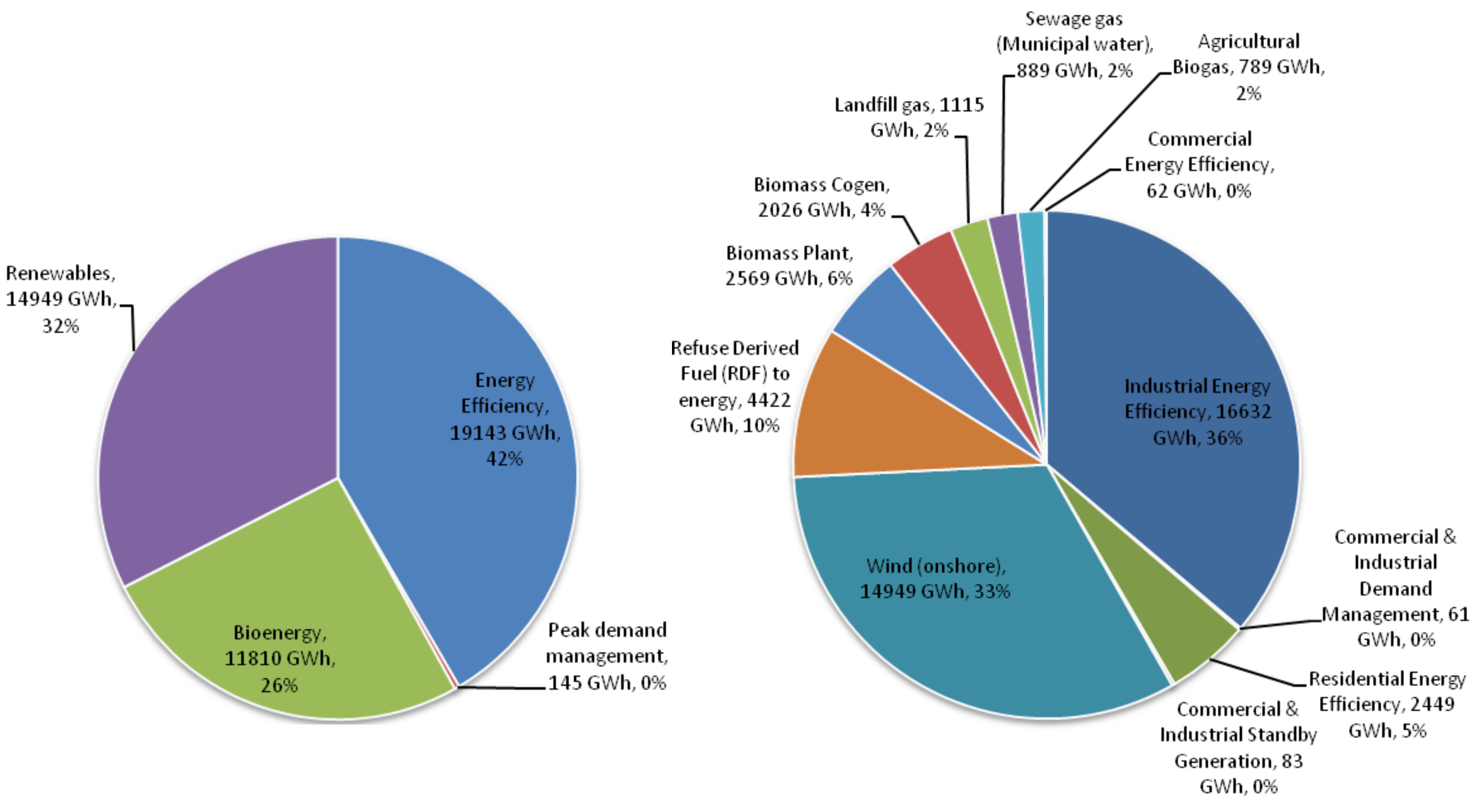


Figure 11 – Case study output, Modelled energy generation to meet 2020-21 shortfall in Optimal Mix case by category (L) and technology (R)



4.4 Discussion

4.4.1 Deployed technologies

Inspecting the technologies deployed to meet Australia's 2020-21 constraints under a medium growth scenario in the BAU cases (Figure 6, Figure 8, Figure 9), fossil fuels, combined with renewable and bioenergy are strongly deployed. Over 7,000 MW of wind is deployed alongside some cheaper bioenergy in order to meet the Renewable Energy Target (RET), and these technologies go most of the way to meeting our energy constraint. However, as wind has a low firm peak rating, we are still faced with a large peak supply shortfall, meaning that 6000MW of peaking open cycle gas is deployed, combined with 600MW of additional black coal capacity to ensure reliability baseload and peak supply. Approximately 500 MW of capacity was gained by improving the efficiency of existing coal-fired power stations.

In the Optimal Mix case (see Figure 7, Figure 10, Figure 11), network costs mean less than 5000MW is deployed. The wind capacity has been replaced by bioenergy, which has also replaced hydro efficiency. 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 options also offer more than enough energy to meet the energy generation shortfall, resulting in some cost savings from avoided fossil fuel generation.

4.4.2 Costs

As can be seen from Table 3, the cost of deployed technologies is substantially lower in the Optimal Mix case relative to BAU. Overall, costs to meet energy and peak capacity shortfalls to 2020-21 are $2.9 billion/yr lower in the Optimal Mix case where DE options are strongly deployed, representing a 43% cost saving. Of particular note are network costs, which comprise almost $2 billion of the $2.9 billion saving. The capital, variable fuel and operation, and carbon costs of the Optimal Mix case are also lower.

4.4.3 Emissions

Emissions from the newly deployed technology options are 0.4 MtCO_2-e in the Optimal Mix case, compared to 4.3 MtCO_2-e in the BAU case. An additional 6.5 MtCO_2-e 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 greater is because most of the energy generation shortfall was met through the renewable energy target in both cases, and most of the remaining investment in the BAU case was in open cycle gas turbines, which – as a peak period generator only – has a low capacity factor. In order 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 or are close to reaching their anticipated retirement age.

To demonstrate this point, another iteration 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%

saving ($360 million per year) compared to BAU case. The 7000MW of coal retirements could be replaced with 2,900MW of commercial energy efficiency, 2,400MW of industrial cogeneration, 1580MW of solar thermal with storage and approximately 700MW of combined cycle gas. Approximately 6000MW less wind investment would be required compared to BAU as 'firm' renewables such as solar thermal and bioenergy are more cost effective at achieving dual goals of supplying energy and firm peak generation.

4.4.4 Supply/demand balance

In the Optimal Mix case, DE demand reduction opportunities reduce expected 2020 peak demand by 10.3% to 55,574MWp, whilst annual energy demand is reduced by 6.9% to 260496GWh. As a reference, 2011 demand figures were 47,062 MWp at the peak and 224,824 GWh annually.

4.5 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 costs and greenhouse gas emissions. The $2.9 billion per year saving occurs 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 another iteration of the model, retiring 7000MW of existing coal generation would reduce electricity sector emissions by 16% at a 5% lower cost compared BAU.

D-CODE compares side-by-side a case that simulates how current Australian electricity markets act, with imperfections and bias towards existing centralized supply side solutions to future energy demands, with an environment simulating one where institutional barriers to DE are removed and the economic potential of these technologies and practices can be realized. 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.

5 Conclusion

The D-CODE model has been developed by the Institute for Sustainable Futures in response to the lack of information available to compare the costs and benefits of different “decentralised energy” opportunities. By including network infrastructure costs in the generator equation, it is possible to compare the ‘full cost impact’ of a range of different technology options for meeting our energy services needs, be it using supply or demand side approaches. D-CODE has been purposefully 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 imperfections in the current electricity market.

Discussions of the wider implications of the findings of D-CODE are covered in other iGrid Project 4 Working Papers. For further discussion on the nature of the market imperfections leading to under investment in DE technologies, refer to *Working Paper 4.1 - Institutional Barriers to Intelligent Grid* (Dunstan et al. 2011a). For a discussion on the policy options to overcome the institutional barriers to unlock the energy sector benefits shown in D-CODE Optimal Mix Analysis, consult *Working Paper 4.2 – 20 Policy tools for Developing Decentralised Energy* (Dunstan et al. 2011b). For more information on mapping the specific opportunities for cost-effective DE deployment within the electricity network see *Working Paper 4.4 – Mapping Network Opportunities for Decentralised Energy: The Dynamic Avoidable Network Cost Evaluation (DANCE) Model*. For industry feedback on the development of the D-CODE model and other iGrid Project 4 outputs, see *Working Paper 4.5 – Stakeholder Consultation Report*. Finally, all of the above working papers are drawn together in the more concise *Australian Decentralised Energy Roadmap*, which suggests direction for further development of the DE industry over the coming 10 years.

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Appendix 1 – Review of other models

To properly frame the research space within which the D-CODE Model fits, it is necessary to review the most relevant of the numerous models and approaches that have been applied (around the world) to assess the costs and benefits of energy sector investment options.

A.1.1. Review of existing models and approaches

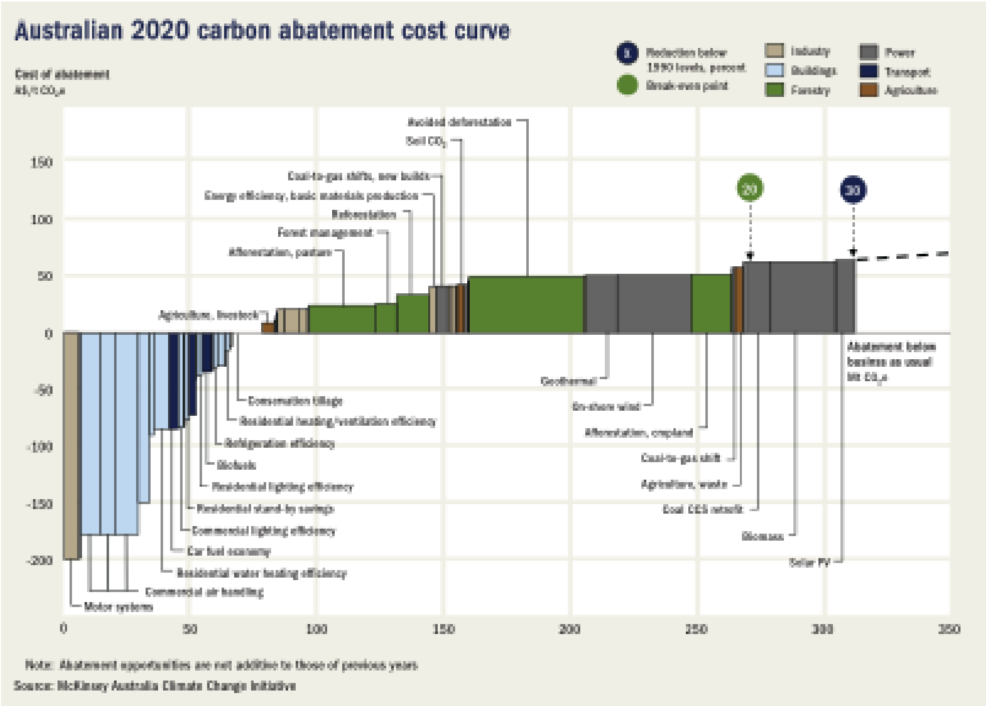
The Lawrence Berkeley National Laboratory (LBNL) provides a review of modelling approaches for energy sector service provision (Gumerman, Bharvirkar et al. 2003), outlining 52 separate models primarily from North America as well as some international efforts. The survey includes a brief description of each model's capabilities, where it can be accessed, and whether it is freely available. The review reveals significant variation in purpose, target audience and commercial intent across the field. Many of these models are no longer available, presumably because they failed to find the appropriate niche within the rapidly changing energy market. This underscores the importance of having a well-defined target user group and a modelling purpose for which high demand exists.

The LBNL review, along with researchers' knowledge and industry internet search engine-based research, revealed several models and costing approaches of similar purpose, although none identical to that proposed in D-CODE. This remainder of this section will provide a brief outline of each of the existing models with relevance in informing the development of the D-CODE model.

A.1.2. McKinsey Carbon Abatement Cost Curve

McKinsey (McKinsey & Company 2008) developed a least-cost carbon abatement curve (see Figure 12) 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 & 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 12).

Figure 12: Carbon abatement cost curve (McKinsey & Company 2008)



From Figure 12 it can be seen that motor system improvements and commercial air handling improvements will each reduce GHG production by about 7 Mt CO2-e annually, and that the current cost of implementing these measures is actually negative. Negative cost of CO2-e emissions here indicates that if market barriers can be overcome, these measures are cost-effective even if the markets were to pay for entities to emit GHGs.

It is reported by McKinsey that ‘power offers the greatest volume of abatement potential, at 39 percent 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.

A.1.3. Distributed Energy Solutions (DES) Compendium

The NSW Sustainable Energy Development Authority's 'Distributed Energy Solutions (DES) Compendium' (SEDA 2002) was the work upon which the D-CODE model was originally intended to build. The DES Compendium was commissioned by the (then) NSW electricity regulator, the Independent Pricing and Regulatory Tribunal (IPART) to investigate the cost and thereby the economic feasibility of distributed energy in providing the state's energy services. A total of 35 feasible DE technologies are 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 is not a model in itself, but provides utilities with the information needed to inform preliminary assessments of decentralised generation and non-network alternatives to network expansion. The D-CODE model will create a platform to harness the basic information provided in the DES Compendium and allow 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 make the tool useful to a range of stakeholders. The benefits of DE resources can be approached both from the perspectives of emissions reduction and energy service provision.

It is important to note that cost and technical data and regulatory environments have evolved somewhat since 2002 for most technologies, and thus D-CODE will 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 looks at the significant value that can be tapped for decentralised energy from deferred or avoided network augmentation, the 'total value' of decentralised energy options at specific locations on a congested grid system can be determined.

A.1.4. LEAP: The Long-range Energy Alternatives Planning System

As explained by (Heaps 2008), LEAP is a tool developed at the Stockholm Environment Institute for global application to medium- to long-term policy analysis in the energy sector and for broader climate change mitigation. It is a tool to enable the economy-wide modelling of different energy and resource systems, designed to track 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”(Heaps 2008) on the demand side to ‘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.

Analyses are generally performed on an annual basis over a period of 20 to 50 years, which distinguishes the intended policy audience from that of D-CODE to some extent. However, finer temporal detail such as time of day or season is possible for electricity sector calculations as required to analyse load variation.

Other key features very 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 low initial data requirements, with but flexibility for detailed inputs if data is available, allowing simple and rapid initial analysis, with room for greater complexity as required.

Like the D-CODE model, LEAP is also a full decision support system (DSS) with ‘extensive data management and reporting capabilities’ with the capability to both forecast future scenarios and 'backcast' historical scenarios. LEAP has importing and exporting compatibility with Microsoft Office applications.

LEAP is a very powerful tool that covers similar territory to D-CODE. As it is not specifically targeted at decentralised energy resources, it may be more difficult to promote as a means of getting the message about decentralised energy options across to short term policy makers and utilities. LEAP is less simple than D-CODE. While it appears that D-CODE could potentially be designed to integrate with LEAP software if D-CODE covers areas or approaches not possible with LEAP (this needs to be checked with experimentation with LEAP), this needs to be considered carefully as LEAP is not free to all users (only those in developing countries and to students), which could pose a barrier to its utilisation.

A.1.5. Next Generation Utility

Next Generation Utility (NGU) is being developed by the Energy and Resources Team at the Rocky Mountain Institute in Colorado, USA (Rocky Mountain Institute 2009). The project shares common goals with the iGrid research cluster: to provide information towards replacing traditional centralised baseload generation with dynamic decentralised demand- and supply-side responses with the aims of reducing carbon emissions and improving the cost-competitiveness of the electrical system. The technologies included in NGU are comprehensive and as per the D-CODE model. 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 years. The model can be applied to complex or simpler scenarios through a modular design and at a broad range of scales 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 methodology. Outputs include supply profiles ranked in order of least short-run marginal operating cost, CO_2 emissions, cost and reliability. For modelling of future scenarios the user controls CO_2 pricing, energy growth rates, energy efficiency and energy storage penetration.

Total DG potential from different regions is obtained from a range of existing studies. Variable renewable energy generators are assumed to have certain capacity factors at different times of the day throughout the year based on the linkage of geographic location and measured or modelled renewable resource data. Firm renewables are treated like traditional baseload generators.

NGU is a very powerful model that takes an engineering approach that includes cost data, rather than an economic modelling approach. Essentially the contribution that decentralised energy resources can make to total energy and peak demand, and to cost and emissions reductions, can be discerned from the NGU model, however the data needs are far greater than for D-CODE due to the complexity of the hourly dispatch model. While adapting the NGU model to the Australian context would be of significant value, the D-CODE concept has currency in its simplicity, accessibility and engagement of key actors for policy purposes.

A.1.6. Other complex system-wide electricity modelling tools

Distributed Power Economic Rationale Selection (DISPERSE): DISPERSE is a proprietary modelling tool developed by Resource Dynamics Corporation designed to estimate distributed energy market potential within a specific geographic region (Gumerman, Bharvirkar et al. 2003). The model performs a 'bottom-up' analysis, starting with a spatial database of high demand sites to create a regional electric and thermal load profile. Distributed energy supply options are then assessed based on unit price and performance data, however it is not clear whether energy efficiency options are available within the selectable portfolio. The model output is a life-cycle cost economic analysis of DE options against grid electricity, with results aggregated wherever the model returns cost-effective DE opportunities, to produce an estimate of DE market potential for the region.

Resources for the Future (RFF) Haiku Electricity Market Model: The RFF Haiku model simulates regional and interregional electricity markets in the USA, 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. The model is reported to be free access but does not appear to be currently available online. It is worth noting that Haiku assumes that there are no transmission constraints within regions (Paul and Burtraw 2002), rendering it unsuitable for use in harmonising with DANCE, the sister model of D-CODE.

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 for 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 detailed demand-side modelling with 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).

Electricity Asset Evaluation Model (EAEM): The EAEM is held by Energy Resources International, Inc. and is a tool developed with 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. It 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. They demonstrated the capability to solve for maximal total system costs and benefits across all asset investment in generation and transmission and distribution (T&D). No assessment of demand-side management was made.

Real Options Model:(Kumbaroglu, Madlener et al. 2004) present an investment planning model that integrates technological learning curves for renewable energy within a 'dynamic programming formulation featuring real options analysis' (Kumbaroglu, Madlener et al. 2004). It enables the demonstration in the Turkish context that a least-cost electricity supply sector planning approach will not lead to renewable energy investment with targeted policy measures, while providing insight into the implications of uncertainty on the uptake of emerging renewable energy technologies.

Other proprietary models of the Australian National Electricity Market include WHIRLYGIG (AGL, WWF et al. 2006), PROPHET (Intelligent Energy Systems 2006), PLEXOS (McLennan Magasanik Associates 2004) and STRATEGIST (McLennan Magasanik Associates 2009).

Economy-wide Top-Down Models: Numerous other economy-wide models exist which have some power sector and greenhouse emission modelling capability, including: ORANI-G general equilibrium model (Horridge, Parmenter et al. 1998); TAIGEM-D (Huang, Li et al. 2000); and the Monash Multi-Regional Forecasting (MMRF) model .

A.1.7. Site- or area-specific Decentralised Energy models

For site-specific applications of DE, the HOMER (NREL 2009); (http://www.homerenergy.com/) and RETScreen(Natural Resources Canada 2009); (http://www.retscreen.net/ang/home.php) models are freely accessible via web download and are powerful tools that begin with bottom-up end-use assessments with the ultimate aim of determining financial and environmental costs and benefits of clean energy supply and efficiency options.

Site owners looking to invest in decentralised energy options should utilise these free resources, however these models are aimed at a different target market to D-CODE.

A.1.8. Conclusion

It is evident from the above that the detailed and complex economy-wide and electrical system-wide models are well developed both in Australia and abroad, and while DISPERSE, Haiku and MARKAL have useful applications for similar policy purposes to D-CODE, there remains an unfilled niche for an open access, simple and transparent modelling tool. In the areas for which it was designed, D-CODE is requires less detailed data than these models and it is therefore more accessible. Further, the proprietary nature of most of the software is incompatible with the goals of iGrid Project 4. It should be noted, however, that the Australian MARKAL model links to a database containing economic costs and engineering specifications and emissions coefficients which may have significant value as a data source or for cross-referencing with D-CODE data inputs.

Additionally, it is suggested that the application of the EAEM or other models capable of full system simulation (such as MARKAL) to the total system costs and benefits (including T&D) of both supply- and demand-side decentralised energy options represents an important opportunity for further research within or outside the iGrid research program. This may also encourage high-level Australian Government engagement with the issues surrounding the upfront and 'hidden' (network) value of DE and inform debate at the decision-making level within the Ministerial Council of Energy.

In conclusion, while there are many existing models in the energy policy and planning space, this review enables us to argue that D-CODE makes its own distinct and original contribution.